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94th Congress }
2d Session }

COMMITTEE PRINT

LONG-TERM NATURAL GAS LEGISLATION

COMPILATION OF STATEMENTS OF WITNESSES BEFORE THE SUBCOMMITTEE ON ENERGY AND POWER

JANUARY 1976

Compiled by the Staff for the Use of the
SUBCOMMITTEE ON ENERGY AND POWER
OF THE
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
U.S. HOUSE OF REPRESENTATIVES

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TESTIMONY OF SENATOR LLOYD BENTSEN
BEFORE THE ENERGY AND POWER SUBCOMMITTEE
OF THE HOUSE INTERSTATE AND FOREIGN COMMERCE COMMITTEE
IN FAVOR OF DEREGULATION OF NEW NATURAL GAS WELLHEAD PRICE

20 January 1976

Mr. Chairman, I appreciate the opportunity to be here today to discuss this issue which is so critical to the national interest. Over the past several months it has become clear that natural gas deregulation is neither a Republican issue nor a Democratic issue, neither a liberal issue nor a conservative issue. It is simply an issue that requires the best collective judgement of the Congress. In October the Senate took a wise, but politically unpopular step when it approved the Pearson-Bentsen bill by a vote of 58 to 32. I am absolutely convinced of the wisdom of the Pearson-Bentsen approach. Now I am seeing encouraging signs that the American public will not be deceived by election year maneuverings and will welcome a frank and workable solution to the natural gas problem.

We can no longer afford delay in getting on with the job of increasing natural gas production. Time is of the essence. If producers are not given the certainty they need to make the necessary investments, we will be hearing even greater cries of "emergency" next winter. And next winter might not be so kind as this one.

Natural gas is our premium fuel. It is clean burning and efficient. It is the optimum fuel from the environmental viewpoint. But the hard truth is that we are running out of gas. As we do, industries and utilities will be forced to convert to fuels posing greater environmental challenges. The more gas we produce, the cleaner will be our air.

With a program of continued regulation, simple economics will dictate that the more expensive gas be left in the ground and the wells capped. This would be a foolish mistake if we were to let it occur. We should produce every economically feasible cubic foot of this precious fuel.

All the experts agree that the natural gas situation must be addressed by some kind of action. Maintaining the status quo is unacceptable. The past two decades of federal regulation of the wellhead price have produced an economic nightmare. Our best fuel is selling at the lowest price, and those who have depended on it are finding it increasingly unavailable. Jobs are at stake. Home fuel supplies are jeopardized. Producers are unable to produce all there is. And the national dependence on OPEC grows.

In the spring of 1973 I filed a bill to deregulate the wellhead price of natural gas. In November of that year I testified at Senate hearings on natural gas. That was three years ago. And today there is still no law on the books addressing the problem.

Last spring Senator Pearson and I joined in co-sponsoring an amendment in the nature of a substitute to the Senate Commerce Committee's natural gas bill, S. 692. That amendment was the beginning of the legislation that finally passed the Senate on October 22 of last year as S. 2310. In the period that intervened between filing the Pearson-Bentsen amendment and the passage of S. 2310, the Senate engaged in many hours of discussion and debate. The attention of the full Senate was focused on the alternate choices for almost two months. Thirty-five amendments were acted on by the Senate during floor debate. Judgements were made only after careful consideration -- and some of them in the end were 180 degrees from the initial viewpoint. The vote on final passage is reflective of the broadbased support for deregulation.

Although there are some provisions in S. 2310 which I oppose because I believe them to be unwise, it is by all means a workable piece of legislation which should be acted on by the House in one form or another. I strongly urge the House, for example, to reject any proposal which would impose a price ceiling on the intrastate natural gas markets.

The definition of "new gas" in the Senate-passed bill also should be modified to permit new gas treatment for in-fill drilling and for expiring contracts. This will permit the redrilling of old and marginal fields such as the San Juan Basin in New Mexico or the Yates Field in the Permian Basin for increased production. It also will encourage enhanced recovery. The measure proposed by Congressman Krueger contains provisions which would remove this obstacle to increased production.

I strongly support the provisions which accord to certain agricultural uses priority for natural gas second only to residential and small users and public health and safety requirements.

We must also begin to phase on to other fuels electric power generation facilities who burn natural gas as a boiler fuel and who are able to use other fuels as a substitute. The impact of a phaseout in my State will be momental. Today, about 98 percent of the electric power produced in Texas is generated by natural gas. However, the utilities in Texas have recognized for some time now that natural gas is a premium fuel which should be reserved for higher order uses.

Adoption of the Pearson-Bentsen-Krueger bill will free for other uses boiler fuel gas amounting to 16 percent of present consumption.

I strongly urge the House to act quickly and decisively on the Pearson-Bentsen-Krueger bill.

The choice of the Congress is clear. Either the American consumer will have gas at reasonable prices, or there will be continuing shortages. The time for studying the problem has passed. Today it is time to act.

I am sure this Committee is aware of the broad-based national support for the Pearson-Bentsen-Krueger bill. Over twenty farm organizations have endorsed it. Producers -- both independent and major -- have endorsed it. The interstate pipelines have endorsed it, as have the gas distribution systems. Add to this the large list of industrial users who support it and you find what I describe as a consensus.

We must assure that there exist market incentives for the full development of our domestic natural gas reserves, natural gas reserves which are increasingly more expensive to find and develop. It is apparent that the present regulatory scheme acts as a disincentive to the exploration for and development of these new higher cost natural gas reserves. The wellhead price of natural gas must be permitted over a period of time to nearly reflect market conditions in order to attract the risk capital necessary to increase our natural gas production and to redistribute among other energy sources, demands which can be fulfilled by other fuels. Because of the rapidly expanding curtailment rate and because of the time lag involved in obtaining actual production after investment decisions are made it is essential that our decision be made now. We have clung to outdated policies too long.

Phased deregulation can reduce the shortage of natural gas. More regulation, on the other hand, would only increase the shortage.

In conclusion, Mr. Chairman, I would like to make this final point. The real issue in this debate is whether the Congress will adopt a policy which will encourage the production of domestic reserves rather than foreign reserves. Either we leave precious domestic resources in the ground or we produce them. If we don't produce them it will result in the transfer of American wealth to the OPEC producers. And that transfer will be at the expense of the American consumer as well as the producer. The producer can get into some other business. But the consumer must still have fuel. And if that fuel is the more expensive foreign-produced version, rather than natural gas, then the American consumer will have been the victim of a cruel joke.

Because of the nature of our natural gas markets, it will be many years under deregulation before the price of gas to the gas consumer will ever reach the btu equivalent of oil. Any deregulation of new gas is necessarily phased deregulation because of the old flowing gas already in the pipe under long term contract. What this means is that the American consumer who is able to get gas will have it for an advantageous price. The savings to him because of not have to rely on alternate fuels are tremendous. We should make this saving available to as many consumers as possible, and the way to do this is to increase production through deregulation.

It's a case of simple economics, Mr. Chairman, I urge you and your Colleagues to follow the good judgement of my Colleagues in the Senate and pass the Pearson-Bentsen-Krueger bill.

Testimony of Rep. Donald M. Fraser before the Subcommittee on Energy and Power, House Committee on Interstate and Foreign Commerce. January 20, 1976

Mr. Chairman, members of the Subcommittee, I appreciate this opportunity to appear before you today.

I have come here to urge the Subcommittee to make needed changes in the existing system of natural gas regulation. I believe that the nation's natural gas problems can best be solved by improving and extending federal regulation in such a way as to reinforce the primary aim of the 1938 Natural Gas Act, namely: "to protect consumers against exploitation at the hands of natural gas companies."[1]

H.R. 8892, the Natural Gas Production and Conservation Act, which my colleague from Wisconsin (Mr. Obey) and I, along with 26 other members, have introduced in the House,[2] would deal with natural gas problems in the following way:

- By setting a firm and uniform pricing policy for all domestic natural gas supplies, our bill would draw new onshore supplies back to the interstate market.
- By removing expectation of higher prices and at the same time basing prices on prospective costs and capital-attraction needs, with automatic cost adjustments for

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[1] 15 U.S.C. 717, Note 3.

[2] See Appendix A for list of identical bill numbers and cosponsors.

inflation, our bill would remove the present inclination to postpone and slow down new development.

- By establishing firm priorities of end-use, our bill would assure dependable supplies of fuel to residential consumers, to agriculture, to essential services, and to industries for which natural gas is an indispensable element, either as fuel or raw material.

H.R. 8892 is similar to a bill introduced in the other body last February by the distinguished Senator from South Carolina (Mr. Hollings) and to S. 692, the bill ultimately reported out by the Senate Commerce Committee in June.

I plan to outline the specific provisions of our bill and point out the differences from its Senate counterparts. But I would like to use my time mainly to discuss the general nature of the natural gas supply problem in order to make clear why our proposal provides a solution, and deregulation does not.

THE NATURAL GAS PROBLEM:

There seem to me to be three major elements in the current natural gas supply situation:

First: resource constraints, which will remain with us no matter how high the price of natural gas.

Second: the inadequacy of the current regulatory system, which on the one hand permits the interstate market to lose out to the unregulated intrastate market and on the other hand, provides a disincentive to exploration and development by fostering a climate of uncertainty of price for new gas.

And third: the lack of workable competition, both structural and functional, in the natural gas industry, a lack which makes continued regulation imperative in the public interest.

Simply removing controls and deregulating might take care of the second of these factors, but would fail totally to deal with the other two.

Let's look at each of these elements in turn:

RESOURCE CONSTRAINTS:

Higher prices will not necessarily elicit greater supplies. Unfortunately our natural gas reserves are running out. A December 1974 Federal Power Commission staff report noted:

> Conventional U.S. gas production has reached its peak and will be declining for the indefinite future.... From here on we must make do with less gas in absolute terms.

We are running up against limitation of resources. The U.S. Geological Survey in May 1975 revised downward previous estimates of reserves to 322 - 655 trillion cubic feet (tcf), or only 15 to 30 times current production levels. In June the Survey cut these estimates further.

The Administration's own Project Independence Report acknowledges that a $2/mcf (thousand cubic feet) natural gas price in 1985 would essentially not get the lower 48 States any more natural gas than an 80¢/mcf price would.[3]

A GAO report released last week concludes that there is no likelihood that deregulation would bring an increase in natural gas supplies. At best, the steady decline in production might be somewhat slowed. The GAO study confirms that there are constraints on supply which price cannot influence.[4]

(GAO admittedly failed to consider the impact on supply of our proposal to extend regulation to the intrastate market.)

INADEQUACY OF THE CURRENT REGULATORY SYSTEM:

Disparity of Prices in Inter- and Intra-State Markets:

A firm and uniform pricing policy, as envisioned in H.R. 8892, would remove one of the principal inadequacies of the current regulatory system, namely the wide disparity between inter- and intra-state new gas prices, which keeps new onshore supplies within their state of origin. Under the OPEC stimulus, the price of gas sold in intrastate markets has risen from 16¢/mcf in 1968 to more than $2/mcf today.[5]

---

[3] Federal Energy Administration, Project Independence, final Natural Gas Task Force report, November 1974, p. xii.

[4] Comptroller General of the U.S., Report to the Committee on Government Operations, House of Representatives, "Implications of Deregulating the Price of Natural Gas," January 14, 1976, p. 56: "With deregulation natural gas supplies would fall about 13 percent below 1975 supplies to 19 tcf. ... The probable major impact of high prices on production in the lower 48 States would be to slow, but not to reverse, the downtrend of production." Deregulation "would have little or no positive impact on natural gas from Alaska. . . ."

Under the existing regulatory system no new onshore gas is flowing into interstate pipelines. More than half the natural gas produced in the lower 48 States in 1975 was consumed within the States in which it was produced.[6] Roughly one-third of all U.S. natural gas gets used up in three of our main producing States -- Texas, Louisiana, and Oklahoma, where most of that gas goes to industrial boiler use.

Regulation, therefore, to be effective, must be complete and must be extended to intrastate supplies.

Uncertainty of Price:

As a corollary, price ceilings, to be meaningful, must be firm and uniform. Since 1968 when the Nixon Administration began its push for deregulation, natural gas prices have had a speculative aura of impermanence which has encouraged producers to delay investment and development.

---

[5] The average price for interstate gas in 1974 was 35.5¢/mcf. The average for intrastate gas was $1.25/mcf, although this is only "estimated . . . no one really knows for sure." Laurence Kumins, "Economic Impact of S. 2310's Pricing Provisions," December 31, 1975, Library of Congress, Congressional Research Service, p.1.

[6] Comptroller General, op.cit., Figure IV, p. 43. 10.4 tcf out of a total 20.5 tcf.

6-6-6

It is only natural that gas producers are unwilling to commit new gas supplies to interstate pipeline companies at the current regulated wellhead price for new gas of 52¢/mcf, when they can sell that same gas for as high as $2 within the producing State. Nor is it unnatural that holders of Federal leases offshore, which by definition come under Federal regulation, are reluctant to bring on supplies which they must offer at a price one-fourth of what they could get under deregulation.

Incentive Under Continued, Extended Regulation:

Gas producers at present would have more than adequate incentive to bring on new supplies were they not holding out for incomparably larger gains under deregulation. Under deregulation, profits to producers would increase substantially. Natural gas producer revenues, which now amount to roughly $9 billion a year, would increase to $31 billion by 1980, according to GAO's January 14 report. Under the current system, yearly revenues would rise to about $18 billion a year over the same period. GAO does not consider what would happen under our proposal.

The present system guarantees producers a 15-18% return on investment, a guarantee given to no other American industry. Regulated gas prices, with the FPC stretching its price-expanding authority to the utmost, have risen at an average rate of 30% a year since the beginning of the decade. For those same five years, unregulated gas prices rose roughly 600%.

In July 1971, natural gas producers in the South Louisiana producing area -- the principal producing area in the country -- declared themselves satisfied with a 26¢/mcf ceiling price, which represented an increase of 30-53% over the previous ceiling. The new price, they said, would provide the stimulus needed for additional production through 1977. Today those same producers say that 75¢/mcf does not provide an adequate incentive, and they seek unregulated prices of more than two dollars.[7]

---

[7] Southern Louisiana Area Rate Proceeding, FPC Docket AR69-1, decided July, 1971. The pledge taken by almost every producer respondent in that case was as follows:

> Each producer individually represents to the Commission that the ceiling prices and other provisions contained herein provide incentive for the exploration for and development of gas reserves in the Southern Louisiana Area. In view of the nature of producing and finding hydrocarbons, it is unrealistic to expect producing companies to guarantee that the ceiling prices and other provisions contained herein will elicit a specific supply of gas; however, it is believed that the ceiling prices and other provisions contained herein will make funds available to the producing industry and create a regulatory atmosphere which should provide an incentive for a substantial increase in exploratory and developmental activities and make a major contribution to bringing forth additional supplies of gas from the Southern Louisiana Area to meet the demands of all consumers supplied by this area. (emphasis added)

3-8-3

Evidence of Withholding of Supplies Under the Current Regulatory System:

In fact, published data show that while the number of successful exploratory gas wells declined slightly from 1955 to 1972 and then picked up somewhat through 1974, the number of developmental wells -- i.e. holes punched in the ground in areas where producers knew there was gas -- dropped sharply after 1960.[8]

The inference is clear. It is only reasonable to assume from these figures that producers have probably been accumulating supplies which can be brought on tap once deregulation and a four-fold increase in prices are in the offing.

(Incidentally, it is worth noting that the decline in oil-drilling activity over the same period was almost entirely responsible for the drop in total drilling although oil went unregulated until 1972 and even though oil prices have, historically, always been several times the price of gas on a btu-equivalency basis. Gas drilling at regulated prices stayed about even.)[9]

---

[8] FPC News, November 14, 1975, p.43. See Appendix B.

[9] See Chart, page 7, John W. Jimison, "Deregulation of Natural Gas the Pros and Cons," July 7, 1975, Congressional Research Service, Library of Congress.

9-9-9

It is easy to find evidence of withholding of supplies in expectation of bigger profits upon deregulation. After all, that is merely good business practice. It is difficult, however, if not impossible, to estimate the extent of such withholding.

At an FPC hearing in July, 1973, for example, the Okmar Oil Company asked for a price ceiling twice as high as the existing ceiling. In response to an FPC query as to what the company would do if it were denied its request, a company official replied:

> The first thing we would do is look again at the intrastate market, because that is the obvious and quickest move. The second alternative would be not to market the gas at all...and take a certain risk that the appreciation of the reserves in the ground over 12 to 24 months, or however long, would more than compensate for whatever the value of the cash flow which we would get from the sale of the reserves over the term of the short-term contract would be. And then we have a third alternative which is a matter of some discussion. Uncommitted gas reserves now are apparently among the finest assets that a company can have -- an independent gas producing company -- and we are constantly, repeatedly, not only with respect to this property but with respect to any reserves we have -- we are being contacted by other gas producing companies, independents and majors, who are interested in buying the reserves in situ. They have expressed their willingness to bid on the come, so to speak, to take the gamble that the reserves would appreciate in the ground.

Again in 1973, when a company in the South Louisiana Area, Belco Petroleum Corporation, sought an increase from the FPC in the ceiling price, from 26¢/mcf to 45¢/mcf, the Company President testified as follows:

10-10-10-

> If it should turn out that the Commission decides that it cannot approve a considerably higher price for natural gas, then we expect that both ourselves and the rest of the industry will defer a lot of their exploratory drilling until they find out what happens in 1977 the year in which the area-rate for South Louisiana was due to expire.

LACK OF WORKABLE COMPETITION IN THE NATURAL GAS INDUSTRY:

I come now to the third and most important element of our natural gas problem -- the lack of workable competition in the natural gas producing industry. The claim that the natural gas supply problem would be solved by letting the marketplace set its own value on this particular fuel rests on the premise that workable competition exists in the industry.

This is simply not the case, although I realize that not all members of the Subcommittee will agree with me. Sales by natural gas producers to pipeline companies are non-competitive in both a structural and functional sense.

It needs to be said in discussing the natural gas industry that we are in fact discussing the oil industry. The leading companies in both industries are one and the same, and gas and oil-producing operations cannot be reasonably separated for purposes of analysis.

Although there may be some 30,000 individual natural gas producers, the industry as a whole is dominated by a few major integrated oil and gas companies. These companies are so interlocked through systems of joint ventures, overlapping directorates, and joint operations in all phases of the oil and gas business, that their behavior often tends to be that of a single company.

In 1974 sales by the top eight natural gas producers made up from 60-99% of new contract sales to interstate pipelines.[10] Even more significant is the fact that in an industry in which production is regionalized, a very few producers as a rule dominate a given region.

In addition to the lack of structural competition inherent in the industry, there is a failure of functional competition in the "field market;" i.e. in sales by producers to pipelines. Producers naturally want the highest wellhead price they can get. That is how a free market system works. But the customers of the producers -- the pipeline companies -- have no incentive to bargain for as low a price as they can get. And under deregulation, that is where a free marketplace would fail to function.

The pipeline companies pass through the entire cost of the gas they purchase to their customers, who for the most part are captive customers. The pipelines are acutely aware of the dwindling nature of the commodity which they sell. They make a profit on the use of their facilities and not on markup of gas. These facilities -- the pipelines themselves -- represent a tremendous investment and make up the largest part.

of consumer gas bills. Transportation costs in fact presently come to about 80% of the price of gas at the "city-gate." So it is in the interest of the pipeline company to pay whatever price is asked in order to get commitment of gas to its system.

Natural gas, then, is a resource which, because of its mode of delivery to consumers, because of the fixed nature of its assets, and because of the structure of the natural gas industry itself, cannot be priced on a free market basis.

President Truman in vetoing natural gas deregulation in 1950, put it extremely well:

> I believe that authority to regulate such sales is necessary in the public interest because of the inherent characteristics of the process of moving gas from the field to the consumer. Unlike purchasers of coal and oil, purchasers of natural gas cannot easily move from one producer to another in search of lower prices. Natural gas is transported to consumers by pipe lines, and is distributed in a given consuming market by a single company. The pipe line companies, and in turn the consumers of natural gas, are bound to the producers and gatherers in a given field by the physical location of their pipe lines, which represent large investments of funds, and cannot readily be moved to other fields in search of a better price.
>
> These characteristics of the natural gas business impose natural limitations upon effective competition among sellers. Competition is further limited by the degree of concentration of ownership of natural gas reserves. While there are a large number of producers and gatherers, a relatively small number of them own a substantial majority of the gas reserves. Furthermore, the demand for natural gas has been growing phenomenally in recent years, and its natural advantages as a fuel, coupled with its present price advantage,

> indicate that demand may soon be pressing hard upon total supplies.
>
> Under these circumstances, there is a clear possibility that competition will not be effective, at least in some cases, in holding prices to reasonable levels. Accordingly, to remove the authority to regulate, as this bill would do, does not seem to me to be wise public policy.[11]

A SOLUTION TO THE NATURAL GAS PROBLEM:

Given this set of circumstances, a "free market" or deregulated price would not be a competitive price. If continued regulation is needed, and I hope you will agree with me that it is, the ideal kind of regulation is that which simulates competitive market conditions. That is what regulation of rates based on cost plus a fair rate of return is. The aim of good price regulation is to set the price of a commodity at the lowest level which will bring forth adequate supplies of that commodity. This is what the Federal Power Commission has been doing for the last twenty years, but it has been doing so incompletely and therefore ineffectively, and moreover, in an atmosphere of speculative expectation of imminent deregulation. (It is worth noting that the price of oil has gone unregulated for most of that same period, and the shortfal of oil is far more serious than that of natural gas.)

---

[11] Harry S. Truman, Veto of Bill to Amend the Natural Gas Act of 1938, April 15, 1950.

We must also recognize the fact that demand will continue to outdistance supply no matter what we do, and that therefore we need to apportion end-use. The free market system -- price rationing -- can't do the job of priority allocation. In intra-state use of gas, the largest part at present goes for boiler use.

Furthermore, we need a mechanism to end the ability of the gas producing companies to withhold production in the short term from the market.

COST OF DEREGULATION TO CONSUMERS:

Before examining H.R. 8892 as a possible legislative solution to the natural gas problem, I would like to consider briefly what deregulation would mean to gas-users.

Deregulation would cost American consumers billions of dollars without assuring them any meaningful increase in supplies. The price of natural gas in the intrastate market has increased 1,100 percent from 1968 to 1975 and yet production in Louisiana and Texas has continued to decline each year.

High prices do not necessarily mean increased production, even without the constraint of limited resources. Increased production follows on higher prices only in a workably competitive market. High oil prices have, as a matter of fact, led to decreased oil production by the OPEC nations in order to maintain the price level.

GAO, concluded in its January 14 report that deregulation could mean an increase in energy costs to U.S. consumers of $75 billion by 1985. The peak impact would come in 1980, when the extra cost to gas users would be $13 billion.

I believe these figures err on the low side. GAO has assumed that the price of gas will be set by the price of an equivalent amount of heat produced from a barrel of imported crude oil, at a price of $12 a barrel. But gas consumers cannot burn crude oil. They must turn to propane or fuel oil, which sells for $15.50 a barrel, or roughly 30% more than crude oil.

The peak impact, according to GAO, would come at the worst possible time, just as we might otherwise be achieving full recovery.

There is widespread concern among consumers over these increased costs despite the magnificent P.R. job of the oil and gas industry to the contrary. The proponents of deregulation claim that if price ceilings were eliminated, the problem of excess demand would disappear: People would use less gas because it would cost more. But these advocates of deregulation insist illogically that the additional cost would be so slight as to be imperceptible.

16-16-16

I ask permission to insert in the record at this point a resolution passed by the 18th Constitutional Convention of the Minnesota AFL-CIO indicating concern over rising consumer costs under deregulation.

Resolution #172, September 9, 1975:

Whereas, the Federal Power Commission recommended removing Federal price controls on natural gas production and

Whereas, removing controls would result in much higher natural gas prices for homeowners and

Whereas, the changeover to other forms of heating and cooling would result in a very expensive modification for the homeowner so as to make this almost prohibitive, and

Whereas, the homeowner is a captive consumer of natural gas; now therefore be it resolved:

That the 18th Consitutional Convention of the Minnesota AFL-CIO go on record to oppose deregulation of natural gas prices at the wellhead.

H.R. 8892: NATURAL GAS PRODUCTION AND CONSERVATION ACT:

If regulation then is necessary, and we firmly believe that in the natural gas industry it is, ideal regulation, as I have said, would be that which simulates competitive market conditions. Our bill permits increases in new wellhead prices of up to 20 percent, based on prospective costs and sufficient profit to attract new capital. In additon, provision is made for automatic adjustments for inflation and for higher ceilings for high-cost production.

17-17-17

Under H.R. 8892, new onshore supplies would come under Federal regulation and would become available to the interstate pipelines that are beginning to run out of gas. Parity of price would be grandfathered in for intrastate and interstate gas prices.

I would like to point out that H.R. 8892 differs from its Senate counterparts in only two ways: In our bill, the national price ceiling for new natural gas is set at 40 to 60 cents per thousand cubic feet, and the exemption for independent producers is eliminated.

In both the Senate bills and our bill, use of natural gas as a boiler fuel would be banned where alternative fuel use is feasible. This ban would become effective, to the maximum extent practicable, within 10 years of enactment.

Highest priority allocation would be given to residential and other small users -- those consuming less than 50,000 cubic feet per day, as well as to agriculture for general farm use, food-processing, and fertilizer feedstock.

The FPC would be granted carefully circumscribed authority to require linkage and transfer of supplies among interstate pipelines to alleviate curtailments to priority users, including industries which cannot substitute other fuels for non-boiler use.

Requirements would be made more stringent for holders of leases on Federal lands and offshore to develop and produce those leases -- a "produce-or-perish" requirement.

I understand that we have provided the Subcommittee staff with a section-by-section analysis of H.R. 8892, which I believe you have. I wish to include in the record at this point, a short fact sheet outlining the major provisions of the bill.[12]

When Mr. Obey and I introduced H.R. 8892 last July, we realized that this Subcommittee would be considering long-range solutions to natural gas supply problems as soon as it had completed work on the Energy Conservation and Oil Policy Act. But we felt that it was important at that time to have a rallying point for those who believe that deregulation would be a serious mistake.

I wish to emphasize that we consider our bill a point of departure and that we earnestly hope that the Subcommittee will go on to draft legislation extending and improving regulation of natural gas. Thank you.

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[12] See Appendix C

APPENDIX A

LIST OF IDENTICAL BILL NUMBERS AND COSPONSORS OF H.R. 8892, the Natural Gas Production and Conservation Act.

Identical bills:

H.R. 9159, 9510, 9939, 9987, 10702, 11160

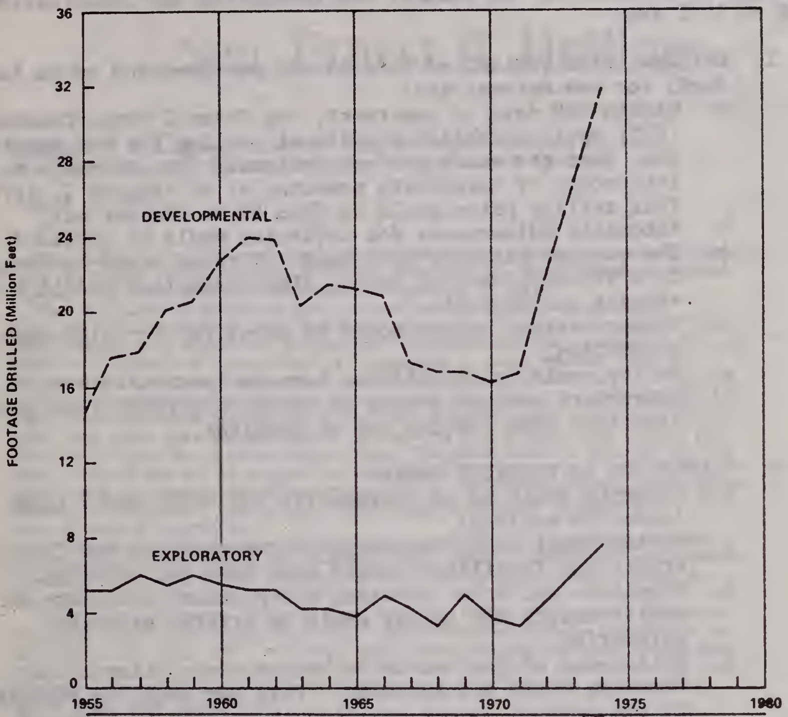
Cosponsors:

Bella S. Abzug, New York
Thomas L. Ashley, Ohio
Berkley Bedell, Iowa
Charles J. Carney, Ohio
Cardiss Collins, Illinois
John Conyers, Jr., Michigan
James C. Corman, California
Christopher J. Dodd, Connecticut
Robert W. Edgar, Pennsylvania
Joshua Eilberg, Pennsylvania
James J. Florio, New Jersey
Donald M. Fraser, Minnesota
Gilbert Gude, Maryland
Herbert E. Harris, II, Virginia
Ken Hechler, West Virginia
Floyd V. Hicks, Washington
John Krebs, California
John J. LaFalce, New York
Anthony Toby Moffett, Connecticut
Robert N.C. Nix, Pennsylvania
James L. Oberstar, Minnesota
David R. Obey, Wisconsin
James H. Scheuer, New York
Gladys Noon Spellman, Maryland
Gerry E. Studds, Massachusetts
Frank Thompson, Jr., New Jersey
Bob Traxler, Michigan
Morris K. Udall, Arizona

APPENDIX B

CHART IV–A

U.S. EXPLORATORY AND DEVELOPMENTAL FOOTAGE DRILLED TOTAL GAS WELLS 1955-1974



U.S. GAS WELL DEVELOPMENTAL FOOTAGE 1/

Yr.		Yr.		Yr.		Yr.		Yr.
55	14.7	60	22.7	65	21.2	70	16.2	75
56	17.6	61	23.9	66	20.8	71	16.7	76
57	17.9	62	23.8	67	17.3	72	22.0	77
58	20.1	63	20.3	68	16.8	73	26.8	78
59	20.6	64	21.4	69	16.8	74	31.8	79

U.S. GAS WELL EXPLORATORY FOOTAGE (Million Feet)

Yr.		Yr.		Yr.		Yr.		Yr.
55	5.2	60	5.5	65	3.8	70	3.7	75
56	5.2	61	5.2	66	4.9	71	3.3	76
57	6.0	62	5.2	67	4.2	72	4.6	77
58	5.5	63	4.2	68	3.3	73	6.2	78
59	6.0	64	4.2	69	5.0	74	7.7	79

Source: Since 1969, American Petroleum Institute (API), Quarterly Review of Drilling Statistics for the United States (QRDS) and World Oil; prior to 1969, American Association of Petroleum Geologists (AAPG) and World Oil.

1/ Developmental drilling data is the difference between total new footage as reported by World Oil and total exploratory drilling footage as reported by AAPG or API.

Note: Service wells, stratigraphic and core tests are not included in the above data.

APPENDIX C

FACT SHEET

The main provisions of the Natural Gas Production and Conservation Act of 1975 are:

1. NATIONAL RATE CEILING of from 40-60¢ per thousand cubic feet (mcf) for new natural gas:
    a. Within 180 days of enactment, the Federal Power Commission (FPC) would establish a national ceiling for new natural gas, that gas which was not dedicated (by contract) to interstate or intrastate commerce as of January 1, 1975. This ceiling price would be from 40 to 60¢ per mcf.
    b. Automatic adjustments for inflation would be provided.
    c. The current historic-cost basis of rates would be changed to a prospective-cost basis, plus sufficient profit to attract new capital.
    d. Higher ceiling prices would be permitted for high-cost production.
    e. Parity would be established between intrastate and interstate new gas prices in order to prevent interstate pipelines from running out of supplies.

2. ALLOCATION ON PRIORITY BASIS:
    a. Priority would go to residential and other small users (under 50 mcf/day).
    b. Agricultural uses, including food-processing and feedstocks for fertilizer, would also have top priority.
    c. Hospitals and other services and products necessary to public health and safety would be granted priority allocation.
    d. Boiler-use of fuel would be banned where alternative domestic fuels are feasible. This ban would be effected, to the maximum extent practicable, within 10 years of enactment.
    e. The FPC would have authority to require linkage and transfer of supplies among interstate pipelines to alleviate curtailments to priority users, including industries which cannot substitute other fuels for non-boiler uses. This authority is carefully circumscribed.

3. REQUIREMENTS TO ENSURE FUTURE DEVELOPMENT OF NATURAL GAS ON FEDERAL LANDS (which includes offshore):
    a. A lessee must undertake and complete exploration and development at the earliest feasible date after leasing.
    b. A federal lease would be forfeited if a producer did not commit his natural gas reserves to an interstate pipeline company within 2 years of discovery of such natural gas.

NEWS
from the office of
Sen. Ernest F. Hollings
D-S.C.

STATEMENT OF U. S. SENATOR ERNEST F. HOLLINGS BEFORE THE ENERGY AND POWER SUBCOMMITTEE OF THE HOUSE INTERSTATE AND FOREIGN COMMERCE COMMITTEE

JANUARY 21, 1976

Mr. Chairman, the Krueger proposal would remove price controls from most natural gas. It raises the basic issue of whether consumers are to be protected against runaway prices for a basic fuel that is a necessity of life.

The proponents of decontrol tried to link decontrol with the emergency legislation in the Senate. But the threat of serious disruption because of natural gas shortages this winter has disappeared. This provides the opportunity for the House to consider and examine decontrol proposals on their merits. Such an examination, I believe, will expose that the case for decontrol has no foundation.

The petroleum industry and the Administration have cleverly tried to imply that sky-high prices would mean an end to the natural gas shortage. Yet, when pinned down, they admit that the shortage of natural gas will persist and, indeed, get worse---no matter how high the price rises. The plain truth is that the ceiling price of $1.30 per Mcf as proposed in this simplified S. 692 will bring forth essentially the same volume of natural gas as the decontrolled price of $2, $3 or higher. The decontrol simply means that consumers will pay billions more for the same volumes of natural gas.

Obviously, Mr. Krueger doesn't believe that decontrol is necessary to bring forth maximum supply because his amendment would delay decontrol in the offshore federal domain until 1981. If decontrol will end the gas shortage, surely we should not suffer six more years of curtailment.

The Krueger amendment would, in fact, make the shortage of natural gas worse. Producers would have every incentive to hold onto their offshore discoveries of new natural gas until 1981, when they could charge sky-high prices. Rather than sell their gas subject to the uncertain standards for price controls in the Krueger amendment, producers would keep it in the ground where it would grow in value faster than money in the bank.

Actually, it is the prospect of decontrol held out by the President and the Senate action that is contributing to the current shortage of natural gas. Until the House votes down this multi-billion dollar bonanza for the petroleum industry, we cannot expect prudent businessmen to make an all-out production effort. Why sell now when the President of the United States promises you prices four times as high tomorrow?

The proponents of decontrol have latched onto the natural gas shortage to justify a position they have been unsuccessfully pushing for the last 20 years. The problem for the nation is that this is the worst time in all those years to decontrol natural gas prices. The reason is that if the U. S. government removes price controls, the price will be fixed by the OPEC cartel. It is not a question of government price controls versus the free market, but rather which government is going to set the price, the United States or the OPEC nations. The wrong answer to that question will cost the American consumer over $100 billion in the next 10 years.

Those advocating decontrol don't like to talk about inflation, which is still a major concern of the Administration, according to the President. And if the Krueger amendment is approved, inflation will increase again next year. The decontrol advocates don't talk about inflation because it would mean a massive income transfer from energy consumers to energy producers. The disposable income of the energy consumers---individuals and businessmen alike---would be severely reduced. Reduced spending on other goods and services, combined with a high-level of inflation, would reduce the nation's purchasing power and would contribute substantially to arresting the nation's slow economic recovery.

Every member of the House is, I'm sure, concerned about gas supply as well as inflation. Let me stress that a vote for decontrol is not a vote for any larger volume of natural gas for consumers than would be produced under the simplified price controls in S. 692. The Senate Commerce Committee bill would raise the price of natural gas high enough to bring forth all the natural gas that money will buy. All that decontrol would mean is that the American consumer would pay many billions of dollars more for the same volume of natural gas.

Natural gas prices would go up under the ceiling price approach of S. 692, and surely an increase which would bring the price of new natural gas up from 52 cents to about $1.30 per Mcf is enough. Under decontrol, the price would go up to $2 an Mcf---the OPEC equivalent and probably higher as the pipelines desperate for supply would bid against each other, average the price with their old gas and pass it on to the consumers. All of these extra billions will not buy any significant

(more)

quantities of additional gas.

The key fallacy in the decontrol argument is that beyond a certain level, higher prices just won't produce more natural gas. If the price covers costs and a high enough profit to attract capital, then the price is not a bottleneck. The Federal Energy Administration's Project Independence Blueprint Report indicated that a price of 80 cents per Mcf would produce substantially the same volumes as would $2 per Mcf. With inflation, and to err on the generous side, I would propose a price of $1.30 to assure maximum production. This could be escalated at the rate of inflation if higher costs are shown. Certainly, the billions of dollars more which would be charged under decontrol would be a pure windfall to the oil industry.

The reason higher prices won't cure the natural gas shortage is that there isn't enough easy-to-find natural gas remaining in the ground. What remains is in smaller formations, more difficult to find, and in sensitive areas such as offshore, where undue haste in drilling can damage the coastal zone. Therefore, the existing and potential demand for natural gas in the years to come is much larger than the supply that can be found and produced regardless of the wellhead price or the drilling effort undertaken by producers.

My simplified ceiling price approach would end regulatory uncertainty and will do more to alleviate the gas shortage than would decontrolling prices. The volumes of natural gas available will be substantially the same, but my proposal will facilitate the use of coal and synthetic gas made from coal to avoid future shortages. This would be accomplished by regulations phasing out the use of natural gas as a boiler fuel where coal can be used as a substitute, and by making the synthetic gas plants a certified part of the pipeline system. In that way, financing can be obtained and construction at public interest locations facilitated. It also assures that natural gas found on the federal domain is actually produced and that producers cannot continue to withhold or go slow in developing the natural gas resources.

The Krueger amendment would completely eliminate federal price controls on "new" natural gas, except on the federal offshore domain. First of all, it is important to understand just what is meant by "new" natural gas. Mr. Krueger uses the "fountain of youth" approach under which old natural gas becomes new after the expiration of existing contracts. Also, producers can drill new wells in existing reservoirs to qualify for the sky-high prices. Thus, drilling will be encouraged that produces no new gas supply, but just more money for the producers. With these giant loopholes, most of the old natural gas will soon become new, the quantities won't change, but the price will jump from an average of 26 cents per Mcf for old gas to upwards of $2 under decontrol. It is no wonder that the industry supports the Krueger amendment.

When I suggest that decontrolled natural gas will jump from the 52 cents the FPC now allows to upwards of $2 per Mcf, I am being conservative. Actually, the prospects are very real for natural gas prices to escalate to $3 or higher if controls are suddenly lifted. The reason is that the potential shortage is very large and that next winter may be cold. If the huge interstate pipeline appetite for natural gas is unleashed on the very much smaller supply prospects without controls, prices will go up and up. The pipelines can, and indeed are, paying, $3 or even $4 for supplemental gas. They can average it in with the old gas and still be competitive with the sky-high prices of OPEC oil.

The extra bill to the consumer---for the same volumes of gas as under my ceiling price proposal---is truly enormous. The extra expense is relatively small at first, but builds up rapidly. In 1980, Mr. Krueger's alternative would cost the nation's consumers approximately $15 billion more. That is $290 for every American family. In 1985, it could be about $25 billion more per year. And all this money would not produce any significant quantities of additional natural gas.

As I previously mentioned, the Krueger proposal postpones decontrol for six years. It thus builds up an incentive for producers to delay and has none of the production requirements in the offshore domain contained in S. 692. It would thus assure a natural gas shortage in the 1970's and more runaway inflation in the 1980's. There would be inflation in the 1970's also from the decontrol onshore, and the uncertain but unnecessarily high prices that the criteria for regulation offshore the Krueger amendment would provide. One criteria suggests that prices should be high enough to "promote sound conservation." This is a seemingly laudable objective but could be a basis for fixing prices higher than the OPEC priced oil to discourage the use of natural gas.

Actually, no one can say what the price offshore would be under the Krueger amendment. It will probably take the FPC most of the six-year period they are in effect to determine them. In the meantime, gas producers, as prudent businessmen, will sit on the sidelines waiting for that glorious day of decontrol in 1981. The interim price ceilings authority reduces but does not eliminate the uncertainty. I urge the House to reject the Krueger amendment because it will retard the economic recovery in the years ahead and do less to solve the gas shortage than a reformed price ceiling approach. Let's not use the energy crisis as an excuse to rip off the American consumer.

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TESTIMONY BY CONGRESSMAN ROBERT KRUEGER (D-Tex.)

January 21, 1976

MR. CHAIRMAN, Members of the Subcommittee, I am pleased to appear before you today to discuss with you a bill which I have introduced jointly with many other Members of the House. It addresses the problem of securing adequate long term natural gas supplies. And that, gentlemen, is the question: How to gain adequate supplies of natural gas to meet our nation's long term needs.

Congress is a body ill-equipped to respond to every short-term problem. Individual citizens can best do that on their own. Our task is to take a long-term overview and draw the parameters in which individuals can best make their own marketplace decisions.

We of the Subcommittee know that the question of long term natural gas supply has been with us for the past year, but the problem has been with the Nation a great deal longer. Not only the House, but the other body has been concerned with this question, and the bill introduced by Senators Pearson and Bentsen, after amendment, was passed 58-32 by the other body. I shall be happy to discuss that legislation with you at the conclusion of the testimony, but at this time I wish to offer some perspective on our present situation.

Permit me, then, some history. Our Nation was once a wood-burning country, then a coal, and later an oil-burning country (including whale oil), and currently, 78% of our energy comes from oil and gas. In fact, natural gas is our largest single domestic source of energy and its proportional use has grown consistently since the Second World War.

All economists, and most legislators, agree that interstate natural gas is currently under-priced. When we say that a product is under-priced, we do not mean that we would not wish it, and all prices, to be lower. We would all like to see a nickel Coca-Cola and bread at 15¢. We mean simply that compared with other fuels natural gas is under-priced, whether this cost is based on its pollution-free characteristics or its BTU content. Under-pricing encourages use of this precious fuel that is not in the best interests of all our citizens.

Further, we know that gas is a resource for which proven reserves are evaporating. But we also know that it is almost the only commodity in our economy that has for several years been in consistently short supply. People simply cannot get all the natural gas that they want, even if they are willing to pay more for it. In that regard, it differs from other commodities, because with other commodities, higher prices are allowed and therefore can bring on additional supply.

That we have shortages in deliverable gas is unquestionable. The residential consumers in Washington, D. C. currently are forced to have "all electric" homes, not by their choice, but because there is insufficient supply for new residential users in the city. The Federal Power Commission has curtailment lists of pipelines, and has requests from many industries seeking additional quantities of gas. In order to be able to say that there was no shortage under the present system, we would have to find that the FPC has no requests to avoid curtailments. This simply is not the case. Further, our shortage is perilous because, as it worsens (and it will under continuation of the present policy) those users who have contracted for natural gas on "interruptible" contracts, may find that their service is increasingly interrupted.

And the curtailments resulting from "interruptible" contracts do not appear in curtailment statistics.

Those people, then,who have contracts for "interruptible" service, can expect in the future not only to be interrupted more often, but later, to have the expense of changing from gas-burning equipment to equipment that can use some other more expensive fuel. In doing so, there is no net gain to the consumer. Although the GNP indicators may show an increase as a company grows through the massive expense of changing over from natural gas to coal, oil, or electricity, the consumer himself receives no benefit. The money invested in such a purpose is used simply for a conversion that would have been unnecessary had we followed a more intelligent policy.

Every other fuel which we might wish to substitute for natural gas is more expensive than the regulated price of natural gas. As our shortages grow more severe, we either lose the industrial output which we require because of curtailments, or industry shifts to substitute fuels. Currently, of course, the substitute fuel most often used is an imported barrel of oil, and that sells for four times the federally regulated price of interstate gas. Synthetic gas and imported LNG are even higher. Thus, the true value of natural gas in the marketplace cannot be realized by producers, because of federal regulations. Natural gas is our only commodity to be price-controlled in this fashion.

The problem is that we cannot force people to invest in natural gas. Even if we were to bring the intrastate gas under interstate control, there would be no mechanism to force people to invest in finding natural gas for the future. I am as disappointed as other Members of this Committee that some energy companies have invested in circuses instead of energy. In a system, however, in which it is considered to be good husbandry to invest in those things that return the largest profit, it is the legislation of Congress as it has been interpreted by the courts that has made circuses more profitable than the search for new gas. It should not be surprising to us that corporations would seek to maximize their profit. Indeed, they would be subject to criticism and perhaps legal action if they did not. A greater riddle is that Congress should condone legislation that makes investments in circuses more attractive. Perhaps it is our values that have been distorted.

We cannot force people to invest, we cannot regulate effectively the quantity of gas to be produced. All that we can regulate is price. And our present deleterious pricing policies have brought us into our problem of existing shortages, greater impending curtailments, and a bleaker future if we do not remedy this situation.

Congress has never been short of conspiratorial theories, and some people have sought for shut-in gas wells as ardently as Ponce de Leon once sought the Fountain of Youth and Coronado the Seven Cities of Gold. Alas, they have all been disappointed. The Department of Interior, the Federal Power Commission, and every group with substantial expertise that has ever investigated this question has found that there is simply no evidence of substantial quantities of natural gas being withheld in anticipation of higher prices. Yet, even if there were such withholding, it should no more surprise us that some people choose to hold gas than that some people choose to hold stocks on the stock market until they can sell them at a higher price. The real reason that there cannot be substantial withholding of gas is simply that the cost of tying up one's capital in holding such gas would prevent its being held over extensive periods. Our problem is not withheld gas, but withheld investment funds.

Currently, for example, we find that domestic oil sells at approximately four times the price of natural gas. Since the cost of drilling oil wells is essentially the same as that of drilling gas wells, obviously the incentive will be greater to drill oil wells than gas wells. Thus, what the consumer gains by our current policy is a fuel that costs four times as much as natural gas, which is priced by the government that seeks to "protect" him.

We must question, then, how effective we have been in protecting the consumer, and in asking how we find ourselves in this imbroglio, we may reflect that questions dealing with natural gas have always been difficult. In 1925 Justice Brandeis stated that in no other industry were the problems so complex and immense. Facing such problems, officeholders are ever tempted to postpone making a decision. Yet, clearly the time has come to cut our way out of this maze.

Although the Natural Gas Act of 1938 specifically exempted from regulation the "production or gathering" of natural gas, the Supreme Court in the Phillips decision of 1954 determined that not only transportation and distribution costs but also costs paid to producers should be regulated. Justice Douglas dissented.

Following the Phillips decision, the price of natural gas in the 1950's was strongly depressed, and economists studying this period generally concur that the pipelines had substantial monopsony power and were inclined to take advantage of producers. A producer of gas, unlike a producer of oil, has few options on how to ship his product and on who will ship it. Oil can be transported by truck; gas, only by pipeline. The nearest pipeline is likely to be a producer's only potential customer, and he is likely to sell fairly closely to whatever price the pipeline wishes to pay.

That situation helped depress the price of gas, and most gas, consequently, was only found as a byproduct in the search for oil. Gas was not specifically drilled for. In 1950 only 30% of natural gas came from non-associated gas wells. By 1975 the figure had risen until 75% of our gas comes from non-associated wells. However, new onshore drilling is largely for gas in the intrastate market. Much gas that lies in fields near interstate pipelines simply is not sought. Because of this disincentive to search for gas, it is quite possible that our current estimate of natural gas reserves are too low. In the late 1950's the work entitled Resources for the Future secured estimates of gas reserves from twelve different sources. Today we know that every one of those estimates was too low. These resources will be developed most effectively and will be consumed most efficiently if we use a market system in which millions of consumers make their own decisions on whether or not to use natural gas, not by leaving wellhead setting of price to a small group of unelected officials in the Federal Power Commission. The major costs paid by consumers are for transportation and distribution, not for production. The producer receives about the same portion of the consumer's dollar as the farmer receives of the cost of a loaf of bread: about 20%.

The Federal Power Commission has fought valiantly since the Phillips decision to determine what prices will be fair and reasonable, but after the 1954 decision, it soon received over 6,000 cases on appeal and its operations were hopelessly tied up. Indeed, by 1960 the Federal Power Commission estimated that it had a sufficient case load to take it to the year 2043; enough work to delight any government employee seeking job security. Since it proved impossible to handle pricing on a case-by-case basis, the Federal Power Commission then, perhaps recalling Coronado's search for the Seven Cities of Gold, divided the Nation into seven gas producing regions and priced gas according to that policy. But this was also found to be unworkable and was abandoned in 1973. During the period in which area rates were being established, however, rates were frozen at roughly their 1958 levels, where they remained until 1967. Since rates were effectively frozen, producers chose not to go into areas that would produce more expensive gas. The Federal Power Commission meanwhile stated that it was following policies in which it judged the appropriate price by "historical costs." It is clear, however, that to judge by the historical costs of a market in which price was regulated and in which a market mechanism was not allowed to operate, is to find results that must necessarily be skewed. It should not therefore be surprising that since 1961 the ratio of reserves to production has been declining, and since 1968 we have been producing and consuming gas at a rate increasingly faster than we are adding to our known reserves. Last year we used three times as much gas as we found. The number of gas wells drilled peaked in 1960. Since that time well-drilling has become more costly and the fields more easily found have diminished. Our future recovery of gas depends on proven technology and the ability to remove these precious hydrocarbons from areas which have not been productive at current price. Since two-thirds of the world's surface is covered by water and there is no reason to suppose that the areas beneath the sea have fewer structures that could trap hydrocarbons than are to be found on land, it is reasonable to suppose that there are adequate supplies of natural gas, but not, certainly, if it must be sold at a price based on "historical" costs of finding it on land.

The constraints upon supply have been increasingly evident for a number of years. Indeed, a signal of this shortage came in 1967 when the AGA, as the trade organization of the principal purchasing group, the pipelines, shifted from favoring wellhead regulation of prices to favoring deregulation. They did so in recognition of increasingly supply problems and of the fact that their vast capital investment in pipelines would be useless if the pipelines were empty. It is worthwhile to observe that despite occasional statements to the contrary, less than ten percent of natural gas production is from producers affiliated with pipelines.

In 1970 we began to feel our first curtailments of natural gas and we soon after experienced the so-called Arab oil embargo which led to the decline of the importation of petroleum. What many people did not realize was that the problems imposed by the oil embargo were exacerbated by our shortage of natural gas. The FEA required companies to produce additional #2 fuel oil to make up for the shortage of natural gas used in heating. Thus, the shortage of natural gas required more fuel oil to be made from oil, and with a shortage of oil, we had a shortage of gasoline. What those lines at the gasoline stations reflected in part was years of faulty policy with regard to natural gas.

There is much concern about the cost to consumers that would result from an increased cost for natural gas. That is an important question. Equally important, even if politically less sexy, are these: What are the costs of alternate fuels? What is the cost to the Nation of being unable to add new customers for natural gas? What is the cost of substitute fuels? What is the cost of plant expansion that is not undertaken because of insufficient natural gas? What is the cost of the jobs that are lost through curtailments? What is the cost of using electricity for heat, instead of gas, when we know electricity to be more expensive and less efficient? What is the cost of uncertainty in supply for industries that wish to expand? What is the cost to an industry that receives gas now on "interruptible contracts" (costs not shown in our normal curtailment figures)? What would be the cost to the Nation if Congress refuses to act and says simply that the question must be studied longer?

If we are poor students of history spending more time studying the same time data and the failure of past policy, our chances of success will not improve. What is the cost of even longer delays on this question?

I recall, Mr. Chairman, as we sat in an upstairs room at the

Capitol, during many of our long labors last spring that we considered including the question of regulation or deregulation of natural gas wellhead prices. At that time, the gentleman from Ohio suggested that we include consideration of natural gas in that bill, since we had already received much testimony on this question. I believe that it was the gentleman from New York who said, "I'm ready to vote on that question right now." The Senate has shown that it was ready to vote and I believe that the House is ready as well. It is my own belief that the central problem we are addressing was succinctly stated by my colleague yesterday when he said the real question was whether to have more regulation or less. National polls make clear how the American people feel on this question and I believe that the Congress will also respond with the answer "less".

MR. CHAIRMAN, I now stand ready to respond to the committee's questions.

Senator Adlai E. Stevenson of Illinois

January 22, 1976

Statement by Senator Stevenson, Chairman of the Subcommittee on Oil and Gas Production and Distribution, Senate Commerce Committee, at hearings on long-term natural gas regulation before the Subcommittee on Energy and Power, Interstate and Foreign Commerce Committee, House of Representatives:

Federal Power Commission cost-based regulation of interstate natural gas prices has provided insufficient incentives and resources for the development of adequate gas supplies. Natural gas has been diverted into the unregulated intrastate market where much of it is used uneconomically. Serious shortages have developed in the interstate market, and they threaten to grow worse. Up to this point there is general agreement. Beyond it, the Administration, the oil industry, its captives and its representatives, agree that deregulation of newly discovered natural gas is the answer. The opponents of deregulation do not agree on what should be done, and at his late hour are in some danger of losing the fight for lack of a solution. I welcome this chance to propose one.

Deregulation of wellhead prices would add the pressure of demand for natural gas in some 46 consuming states to demand in the producing states where already the unregulated intrastate price for new gas is averaging about $1.30 per MCF. Natural gas prices would rise to even higher levels. Early this winter, and despite mild weather, uncontrolled emergency natural gas sales in interstate commerce rose as high as $3 per MCF. That deregulated gas price is in excess of the OPEC equivalent for oil. The large and relatively inelastic demand for natural gas combined with the cartel price for oil lifts unregulated gas prices to arbitrary and dangerous levels -- levels even higher than the OPEC oil price.

The average price for all flowing natural gas is now about 35 cents per MCF. Since natural gas supplies about one-third of the nation's energy requirements, the quantum jump in a basic cost that would ripple out to inflate the cost of every commodity and service in the economy as a result of deregulation would probably bring back double-digit inflation, a resumption of the recession and raise the levels of unemployment. I have discovered in the Senate hearings that many authorities reported to support deregulation do not in fact do so for these reasons. They oppose continued cost based FPC regulation. But economists in particular acknowledge that there must be some protection against arbitrary cartel pricing of this vital premium fuel in short supply. The real question is not whether but how to prevent cartel regulation of domestic natural gas supplies.

Precisely how high the price would go if deregulated and with precisely what effects in the economy no one can say with certainty. I am aware of industry claims that consumer bills would go up insignificantly because the new gas would be rolled into the price of old flowing gas. But I am also aware that old gas is depleting rapidly, that lines between old and new are difficult to draw, easy to evade, and that the fine print in many contracts for the sale of old gas may permit their renegotiation at far higher prices if new gas is deregulated.

According to estimates prepared by the Library of Congress, deregulation of new natural gas would add 1.5 percentage points to the retail price index by 1977. But no one can say with certainty. In my judgment the estimates tend to be conservative, failing to take into full account the possibility of renegotiated contracts for flowing natural gas, future OPEC price increases, the impact of the gas price on the price of unregulated alternative fuels and the full ripple effect. Similarly, it is difficult to be precise and difficult to project significantly diminished demand for natural gas in the interstate market as a result of deregulation -- except as a result of declining industrial and agricultural activity. I can only urge you to scrutinize closely the self-serving, wishful and simplistic claims that natural gas wellhead prices can be deregulated without an adverse effect on the economy before risking an inflationary influence that might rival the quadrupling of oil prices in an already feeble economy -- and like the oil price increases, produce little more fuel.

Beyond the point at which price increases produce necessary incentives and resources -- they produce windfall profits, inflation and recession, not appreciably more gas.

A price is necessary, therefore, that will produce gas on the one hand and on the other, protect the economy from more cartel energy pricing. A balance should be struck. It is not necessary to increase interstate natural gas prices from the current maximum of 52 cents per MCF to $3.00 and more in order to produce increased supplies of natural gas.

The Federal Energy Administration's original Project Independence Report in 1974 concluded that at prices in excess of 80 cents per MCF, natural gas supply increases would be negilgible. A more recent update of that Report sets the figure at approximately $1.40 per MCF.

The FPC has recently completed a staff study calling for a new natural gas ceiling price of approximately $1.10 per MCF.

The Joint Economic Committee of the Congress has observed that as higher prices produce higher industry revenues, the oil companies outbid each other and "costs will adjust upward to absorb virtually any level of prices and profits. Today's high petroleum prices, therefore, are not the result of -- nor can they be justified by -- increased production costs. Quite the opposite is the case. High costs are a consequence of high prices and profits * * * What the United States has gotten for the high prices and profits in the oil industry is a very high cost energy industry. Higher costs do not yield more oil and gas."

Among many others, the former Chairman of the FPC, Mr. Nassikas, a reported supporter of deregulation, testified on several occasions on the Senate side that some ceiling was necessary to protect the economy against excessive natural gas prices.

In the recently enacted Energy Policy and Conservation Act, both the President and the Congress recognized as much in the case of oil. It would be inconsistent for the Congress, having regulated the historically unregulated price of oil, to deregulate the historically regulated price of gas, just because some change in the status of each is indicated. A sensible price policy and price certainty for each are needed. The Congress recognized as much for oil; it should for gas.

The FPC's emergency pricing provisions produced instant gas this winter, not because wells were instantly drilled and connected -- but because gas was being withheld from the interstate market in anticipation of a deregulated, higher price. For all the protestations to the contrary, gas is being withheld, as you well know. It will continue to be withheld until the rules of the game are established and the expectations of windfalls around the corner are ended. Price certainty at a sound level ought to be the objective in the case of natural gas pricing -- as it was in the case of oil.

As long as natural gas is priced below the BTU equivalent price for oil, producers will seek to produce the more profitable oil. And consumers will seek to consume the lower priced premium fuel in shortest supply. The supply of natural gas then declines while the demand increases. If deregulated, natural gas would be priced at a far higher level than domestic oil. Some producers might then seek gas at the expense of oil. So, it seems to me, the industry is right in saying that price should reflect an equivalency of energy values for these fuels. They are, after all, often substituted for one another and produced in association with one another. A pricing system should reduce the disparity between oil and gas prices. Deregulation of one and not the other or regulation of one without a related regulation of the other could widen the price disparity.

The Joint Economic Committee urges that regulation of prices "make allowance for substantial narrowing of the disparity between the high prices of oil * * * and lower prices of federally regulated interstate natural gas. Coordinated action on oil and gas could permit an adjustment in gas prices at less net cost (or no net cost) to energy consumers on the average."

I agree. To accomplish this purpose I suggest that the new natural gas price be geared to the average price for oil established in the Energy Policy and Conservation Act. In that Act the Congress established a $7.66 per barrel initial domestic average oil price. Natural gas should be priced on a BTU equivalency basis at the same level, rising in the future in harmony with oil. Such a formula would produce price certainty. The complicated and time-consuming cost-based regulation of the FPC would be superseded by a straightforward nationwide ceiling. Under this formula the initial price for new natural gas would be approximately $1.35 per MCF. The gap between domestic oil and natural gas prices would be closed. A comprehensive national pricing policy would be established for the nation's two most vital fuels.

This price would be close to the recent average in the unregulated intrastate market, an increase from 52 cents per MCF in the regulated interstate market (except for short-term emergency sales). It would produce the necessary incentives according to studies of the Senate Budget Committee and the Federal Energy Administration. It produces more incentives than are necessary according to a staff study of the FPC. And it ought to be supported by the industry itself. It takes the industry at its word.

The American Gas Association claims that deregulation is necessary to increase natural gas supplies and that "a realistic figure for the average price of deregulated new gas is $1.50 per MCF which is close to parity with the expected average price of domestic oil at the end of 1976."

This equivalency formula simply gives the industry what it says it expects to get. It also protects the public against any miscalculations.

Such a proposal is formulated in an amendment which I offered on the Senate floor to the Natural Gas Production and Conservation Act of 1975. It failed by a few votes before the oil pricing controversy was resolved. The Senate approved deregulation of natural gas by accepting an amendment offered by Senators Pearson and Bentsen before it approved regulation of oil. The Pearson - Bentsen amendment deregulates new natural gas onshore and continues for five years FPC ratemaking of natural gas offshore. It gives the country the worst of all worlds, FPC ratemaking and a multitude of natural gas prices all unrelated to prices for oil now established under the Energy Policy and Conservation Act.

I urge you to reject that proposal and the all-or-nothing demands of the oil industry and continue the policy Congress wisely adopted in the Energy Policy and Conservation Act by establishing a new natural gas ceiling price equivalent to the nation's average domestic oil price.

There is really no such thing as "deregulation." It is a case of U.S. regulation or OPEC regulation. As between the two, we should put the responsibility for the national interest in our own government.

NEWS RELEASE - - -

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Congressman
WILLIAM J. HUGHES
2nd District • New Jersey
Committee on the Judiciary
Subcommittee on Monopolies & Commercial Law
Subcommittee on Crime
Select Committee on Aging
Ad Hoc Select Committee on the Outer Continental Shelf

FOR RELEASE THURSDAY January 22, 1976

NEW GAS NOT WORTH 42 TIMES THE CURRENT PRICE, HUGHES TELLS COMMITTEE

WASHINGTON, D.C. -- For a two percent increase in natural gas supplies through deregulation the consumer would pay 42 times the current regulated price, Congressman William J. Hughes (D-N.J.) today told a congressional committee.

"And this is a conservative estimate," the New Jersey congressman said in testimony before the House of Representatives' Interstate & Foreign Commerce Subcommittee on Energy & Power.

"It does not even include the near certainty of a price increase by the Organization of Petroleum Exporting Countries (OPEC) and their multinational oil company partners that would accompany the removal of government controls on natural gas prices."

Hughes based his estimates on figures contained in a January 14, 1976 report entitled "Implications of Deregulation The Price of Natural Gas" issued by the General Accounting Office, the investigative arm of the Congress.

The G.A.O. report cited estimates of an additional 400 billion cubic feet of natural gas that would be added to the market supply within three years should Congress lift controls on gas sold in interstate commerce. The 400 billion cubic feet would be an addition to the 19.4 trillion cubic feet of natural gas estimated as available in three years under continued regulation. (The market, which is currently divided nearly in half, maintains controls of a maximum of 53 cents per thousand cubic feet when sold in interstate commerce with prices within producing states three and four times as high where it is approaching the Btu equivalent of the cartel price for oil.).

"The total additional cost to consumers under deregulation is estimated by the G.A.O. at $9 billion. So, for $9 billion, industrial, commercial and residential users would have access to an additional 400 billion cubic feet of natural gas which is the equivalent of $22.50 per thousand cubic feet.

"To fully appreciate the enormity of this profit windfall," Hughes said, "we need only recall that five years ago natural gas producers were enjoying good profits in the interstate and intrastate markets for an average price in both of 29 cents per thousand cubic feet."

Hughes told the subcommittee that while using the $9 billion price estimate of the G.A.O. for costing purposes, he believed that the December 31, 1975 Library of Congress estimate to be more accurate in gauging consumer impact of deregletion. In its study, the Library placed the first-year cost in the range of $12.8 to $14.9 billion. "This would produce an inflationary rate of between 1.2 and 1.4 percentage points and raise unemployment by several hundred thousand," Hughes said.

The G.A.O. report in forecasting economic impact makes the mistake of comparing deregulated natural gas prices to the Btu (British Thermal Unit) equivalent of crude oil rather, as did the Library of Congress, with its actual refined rivals, propane and No. 2 fuel oil, Hughes noted.

"Where the G.A.O. report errs fatally," Hughes told the subcommittee, "is in forecasting figures based upon the preposterous assumption that the OPEC oil cartel will not act to recoup any loss in revenues occasioned by a drop in U.S. oil imports."

In its study, the G.A.O. asserts that deregulation within 10 years will reduce oil imports by 750,000 barrels per day and improve U.S. balance of payments by $3 billion. "It is doubtful, however, that OPEC will cooperate based on its past performance," Hughes said.

As an alternative to deregulation, Hughes suggested the following remedies which forms the basis of legislation he will submit this session of Congress:

-- "First and foremost, we must establish parity between the interstate and intrastate markets by setting a fair single pricing system for all gas sold in the U.S.," Hughes said. This he would accomplish by expanding the jurisdiction of the Federal Power Commission to the intrastate market where prices are now influenced by cartel-induced increases in the cost of oil rather than to traditional patterns of supply and demand.

-- An allocation system that would insure fair allocation of existing supplies throughout the country.

-- Conservation measures including, where practical, a switch from natural gas to substitute fuels.

-- An end to the use of natural gas as a boiler fuel, most commonly in practice within producing states.

-- A requirement that gas producers develop or forfeit nonproducing lease holdings beyond the primary five-year term. "More than 750 or 52 percent of the 1,497 leases in the Gulf of Mexico are in nonproducing status. Those surveyed according to testimony before the Senate Antitrust and Monopoly Subcommittee, are operating at less than half capacity.

"According to an F.P.C. study, eight major oil companies control between 62 and 99 percent of the new reserves depending on the gas field cited. Is it really any wonder, then, given the level of industry concentration in our regulated offshore waters, that these are not being produced with all due haste?" Hughes said.

"To determine why these offshore reserves are not being produced, I sought and was granted the right to intervane in proceedings before the F.P.C. into the status of nonproducing reserves.

"It was a real education. Producer witness after producer witness claimed equipment shortages, lack of capital and repair delays as excuses for nonproduction. Yet while these producers were shouting equipment shortages to the F.P.C across town, at the Export-Import Bank, international representatives for the very same firms were whispering equipment surplus into the ears of officials to the tune of $800 million in loan guarantees."

Hughes blamed uncertainty as the principal cause for the continuing decline in gas dedicated for sale to interstate commerce. "As long as producers believe there is a good chance that they may enjoy deregulated prices tomorrow, they are not likely to strive for maximum production today."

Hughes delivered his statement to the Energy & Power Subcommittee which is considering long-term solutions to the natural gas shortages.

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STATEMENT OF THE HONORABLE WILLIAM J. HUGHES, MEMBER OF CONGRESS FROM THE SECOND CONGRESSIONAL DISTRICT, STATE OF NEW JERSEY, TO THE SUBCOMMITTEE ON ENERGY & POWER, COMMITTEE ON INTERSTATE & FOREIGN COMMERCE, U. S. HOUSE OF REPRESENTATIVES, THURSDAY, JANUARY 22, 1976.

Mr. Chairman, distinguished Members of this Subcommittee:

It was predicted six months ago that by now we might be meeting to discuss long-term resolution of the natural gas emergency amid the backdrop of industrial plant closings and thousands of new unemployed.

As the representative of an area with numerous factories that use natural gas as a feedstock, the thought of such a prospect is best not dwelled upon.

From all indications, most if not all sections of the country will likely ride out this winter's shortage originally forecast to be as great as 52 percent of the contract commitments of several interstate pipelines.

A warmer winter, some say.

Add to that emergency purchases of natural gas by interstate pipelines, the utilization of more expensive fuel substitutes and, I would add, the scrutiny of this and other Congressional Committees and this winter's supply picture has considerably improved.

Now those who overstated this winter's emergency are advising this Committee that our long-term interests are best served by deregulation, phased or sudden. These deregulation advocates include not only the gas industry but the Federal Energy Administration and the reluctant regulators at the Federal Power Commission as well.

I suggest, Mr. Chairman, that they are guilty of overstating their case once again.

I do not doubt that production is declining, that is obvious. What I do question is the industry's assessment at how we arrived at where we are today and where we go from here.

Deregulation in the absence of government access to date to the same reserve and production data available to the industry and the authority to order maximum production or lose lease rights on existing federal lands would, in my opinion, be sheer folly.

It is no less attractive in the phased setting as contemplated by the Senate passed Pearson-Bentsen bill, S. 2310. Because in the present non-competitive market in which oil prices are set, immediate or phased deregulation is tantamount to a surrender announcement to the oil exporting nations.

Clearly, we cannot permit our energy policy to be determined by nations that produce oil for 11 cents a barrel and sell it to us for $12.

The Cost of Deregulation

In the last few weeks in separate reports issued by the Library of Congress and the General Accounting Office, we are able to assess the economic trade-offs that would follow House agreement to the Pearson-Bentsen bill.

The GAO, citing what it believes are obtainable goals under deregulation, forecasts a difference of an additional 400 billion cubic feet of natural gas over what would be produced in three years should regulation continue.

The Library of Congress' December 31 estimate of the first-year impact of gas deregulation to consumers is in the range of $12.8 to $14.9 billion for little, if any, additional supply. This is because of the two to three year lead time between accelerated exploration and marketing of new commercial quantities of gas.

What we would not have to await is an energy shock throughout the economy.

The Library of Congress further estimates the ripple effect of $13 to $15 billion as likely to produce an inflationary rate of between 1.2 and 1.4 percentage points. Unemployment is forecast to increase by several hundred thousand.

And for what? To transfer dollars from consumers to producers on the somewhat shaky premise that these mega-bucks will be invested in searches for new gas supplies in sifficient quantities to make it all worthwhile.

Further, we have no guarantee that this new found wealth would be reinvested in exploration at all. It could just as easily be used to purchase department stores or a three ring circus.

A commendation is in order at this point to the Chairman and the majority on this Subcommittee who drew the line on deregulation and, instead, approved limited deregulated sales to interstate commerce for this winter season and next.

Despite what those in the industry say publicly, Mr. Chairman, this issue has not been studied to death and won't be as long as this Committee continues to have its requests for reserve and production estimates denied on grounds of protecting proprietary information.

An Alternative to Capitulation

My constituents and those of many other Congressmen are on the receiving end of interstate pipelines. In the case of my South Jersey district, we have one pipeline, one distributor and no choice.

In the next few days, I will be introducing for reference to this Subcommittee legislation which in my opinion will insure maximum domestic production at lowest possible consumer prices.

It presents an alternative to capitulation to the OPEC cartel and the major multinational oil companies by establishing a fair price for natural gas and procedures to end the wasteful misallocation of this precious resource that has resulted from the lack of a uniform and coherent national policy.

Most importantly, it would end uncertainty. As long as producers believ there is a good chance that they may enjoy deregulated prices tomorrow, they are not likely to strive for maximum production today.

First and foremost, the bill establishes parity between the interstate and intrastate markets by setting a single pricing system for all gas.

Prices set by the bill would be adjusted for inflation, and could be raised by showing the Federal Power Commission that actual costs are not recouped but, aside from these adjustments, will remain in force for five years.

Other sections establish a fair system for allocating existing supplies throughout the country, incorporates conservation feasures and, provides for the forfeiture of non producing leases, and, as even deregulation advocates now endorse, phases out the use of natural gas as a boiler fuel.

Philosophically, I do not advocate tight government regulation. In a competitive industry, the fewer controls the better -- the market will set the price.

But we need only examine the most commonly cited argument for deregulatic to expose the myth of competition in the oil and gas industry.

21 Years of Regulation

The most absurd assertion, usually compounded by the appearance of a full page ad is that the Congress and the Federal Power Commission are responsible for the present crisis by keeping prices artifically low through 21 years of federal regulation.

Up until 1968, when former President Nixon was elected on a pledge to reduce federal regulation, we had all the natural gas we thought we could possibly use.

The producers, the pipelines and the distributors couldn't sell it fast enough. They entered into 10, 15 and 20-year contracts. Discounts were given to builders who agreed to pipe in gas to housing developments.

For many years after the Supreme Court ordered the F.P.C. to regulate gas prices at the wellhead in 1954, the industry continued to get a better price on the interstate market than within producing states.

This remained the case until late 1970 when interstate gas was sold at a good profit for an average price of 29 cents per thousand cubic feet in both markets.

Proven reserves in fact peaked at 292.9 trillion cubic feet in 1968 but, despite overall price increases of 400 percent in recent years, continues to decline.

Coinciding with a decline and revision of reserve estimates was a gradual shift to the unregulated intrastate market which became a stampede in the winter of 1973 where gas producers were obtaining cartel prices.

Since 1970, more than 90 percent of reserve additions in the lower 48 states have been dedicated to the intrastate market.

In the meantime on federal lands, where gas discoveries are by law dedicated to the interstate regulated system, discoveries and production continued a rapid decline.

Which brings forth a second industry argument, that of industry concentration. It is said that there are some 30,000 producers; that the four major oil companies control but 24 percent of the market and that the 8 largest firms 42 percent, low when compared to the other industries.

Industry Concentration

Dr. David Schwartz, former Assistant Chief of the Office of Economics at the Federal Power Commission, draws an important distinction between market holdings and new reserves. In the latter category, an FPC study found that the eight largest natural gas companies which, not incidentally, are among the largest oil producers, control between 62 percent and 99 percent of new reserves depending on the gas field involved.

And there are not 30,000 producers operating offshore where the Interior Department through witless leasing policies has assisted industry concentration to a handfull of major firms.

Eight major firms control 70 percent of the available known supplies of natural gas onshore and offshore South Louisiana, four of which hold nearly 50 percent; the eight largest firms in the Taxas Gulf Coast control 90 percent of available new gas not yet under contract there, the four largest just under 80 percent.

In the combined fields, eight majors control three-quarters of the new gas finds with the concentration ratio around 50 percent for the four major firms. An eight firm concentration ratio of 50 percent or more is generally regarded as indicative of non-competitive structure within a given industry.

It is really any wonder, then, given the level of industry concentration in our regulated offshore waters, that these are not being produced with all due haste. The prospect of total deregulation by 1981 as contemplated by the Pearson-Bentsen bill and an initial price hike to $1.60 per thousand cubic feet would make it all worth waiting for.

More than 750 or 52 percent of the 1,497 leases in the Gulf of Mexico are in nonproducing status. Those that are, according to testimony before the Senate Antitrust and Monopoly Committee are operating at less than half capacity.

The number of leases in extended term, at last count, was 74. By law, the Interior Department is empowered to yank those leases and resell them to another buyer who can come across with a reliable production plan.

To determine why these offshore reserves are not being developed, I sought and was granted the right to intervene in current proceedings before the F.P.C. into the status of nonproducing reserves.

It was a real education. Producer witness after producer witness claimed equipment shortages, lack of capital and repair delays as excuses for nonproduction.

Yet while these producers were shouting equipment shortages to the F.P.C. across town, at the Export-Import Bank, international representatives for the very same firms were whispering equipment surplus into the ears of those from whom they were seeking loan guarantees.

This, then, is the root of the suspicion of many in this country who believe we'll get all the gas we need domestically at $2.50 or more per thousand cubic feet, or whatever the escalating cost of Btu equivalent alternative fuels is six months or a year from today.

I do not share the belief that production will suddenly leap upon deregulation, but I am dead certain that whatever we do get we'll pay cartel prices for it.

Autos and Energy

To the argument that the gas industry is no more concentrated than, say, the automobile industry, the obvious reply is that you can take a bus, ride a bike, or keep the repair shop happy. There are alternatives which automobile manufacturers must keep in mind in pricing their product, but there is only one commodity that can come out of the end of that pipe to heat your home or run our factories.

A constant supply of new energy, unlike a constant supply of new cars, has become a necessity of life. During this period of extreme shortage, thoughtful allocation of this resource is essential.

Unlike the auto industry, gas producers don't offer rebates to stimulate sales.

A final word on the implications of price fixing, especially as it bears on new contracts suggested by the few producers of Alaskan natural gas.

As a member of the House Judiciary Subcommittee on Monopolies and Commercial law, I was recently furnished a copy of a classic cartel contract under negotiation between Arco and a California utility.

It said, simply, that in no case will gas be sold for less than the maximum price then being obtained by any supplier of Alaskan pipeline gas. Were I an antitrust lawyer at the Justice Department, I would gladly volunteer to prosecute that case.

These, then, are several arguments and rebuttals to deregulation.

It may be that what this nation needs is a restructuring of the oil industry rather than deregulation of natural gas prices.

As a member of the Judiciary Committee, I am currently reviewing the legal obstacles to the timely prosecution of antitrust suits. There is no reason why antitrust suits at the Federal Trade Commission and in the Justice Department should drag on for years without resolution.

The Judiciary Committee's Subcommittee on Monopolies and Commercial Law continues to hold hearings on legislation that would accomplish vertical and/or horizontal divestiture of the oil industry.

Pending the outcome of these hearings, it is a serious mistake to precipitously deregulate natural gas prices and further surrender the power of the government to keep any lid at all on prices.

The GAO Blunder

In closing, permit me to comment on the principal conclusion, and therefore the principal blunder, contained in the January 14 General Accounting Office report entitled: "Implications of Deregulating The Price on Natural Gas."

Total new gas discoveries under deregulation would amount to approximately 400 billion cubic feet more after three years when compared to continued regulation.

This, trumpets the report, could reduce our oil imports by 750,000 barrels per day and improve our balance of payments by up to $3 billion.

While 400 billion cubic feet of natural gas sounds impressive in isolation it is, after all, only a two percent increase over the 19.4 trillion cubic feet of natural gas that the GAO estimates will be available under continued regulation.

Where the GAO report errs, fatally, is in forcasting figures based upon the preposterous assumption that the OPEC oil cartel, now in the driver's seat with deregulation, will not act to recoup any loss in revenues occasioned by a drop in U. S. oil imports.

The GAO compounds its error by assuming in the ten-year life of its study (1975--1985) that the international market will remain stable with no OPEC price hikes.

There are other serious deficiencies in the latest GAO report -- assumptions which, I am sure, many on this Subcommittee have already challenged.

The report is assessing consumer impact, for example, considers a rise in natural gas prices to the Btu equivalency of crude oil (about $1.70 per Mcf) rather than to its actual rivals, propane and No. 2 fuel oil which have a Btu price equivalent of around $2.50 per Mcf. The latter estimate, again by the Library of Congress, is more reliable since it measures comparable fuels.

This accounts for the first-year impact difference of $9 billion by the GAO and the $12 to $15 billion price tag affixed by the Library.

Finally, nowhere does the GAO report examine the option of regulating the intrastate market as an alternative to the status quo or deregulation.

A final argument could be made that even 400 billion cubic feet at an exhorbitant rate is better than no new gas at all. I disagree that we necessarily have to make such a choice.

Uncertainty is the real culprit. I am not convinced that this is an either or situation. The establishment of parity between the interstate and intrastate system that provides for a good return on investment may very well be all that is required to again attract exploration investments.

In the final analysis, the central question is not as complex as the side issues.

What we must decide is whether we can afford to let an international oil cartel and the multinational oil corporations which owe allegiance to no nation determine our future energy policies. An industry that can set the price for gas and oil will ultimately determine the price for alternative fuels as well. An industry that powerful will soon be telling the government how much tax it will pay and under what conditions it will continue to supply this nation with energy.

Clearly this we cannot permit.

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EXECUTIVE OFFICE OF THE PRESIDENT
COUNCIL OF ECONOMIC ADVISERS
WASHINGTON, D.C. 20506

Testimony of

Paul W. MacAvoy, Member
Council of Economic Advisers

Before the

SUBCOMMITTEE ON ENERGY AND POWER
House of Representatives

January 22, 1976

Placing the interstate natural gas industry in the context of the American economy illuminates some important contrasts. While the economy as a whole is advancing strongly towards recovery from the 1974-1975 recession, this portion of the natural gas industry continues along a path of systematic decline in production and underutilization of pipeline and distribution capacity. While other energy industries indicate substantial response to price increases as well as to the demands for energy independence consequent upon the OPEC embargo, natural gas destined for the interstate market follows a path which implies that the embargo did not occur at all. In the last five years, the gas production and distribution industries have been forced upon a path of secular decline in reserves and production. If it were not for the existence of the uncontrolled intrastate market, these declines would undoubtedly have been much greater still.

The contrast in consumption patterns is even more striking. Natural gas is the only natural resource industry now experiencing systematic excess demand, with formal legal curtailment of deliveries, so that those that are seeking this material at controlled prices have had to go to other fuels, to relocate within the producing states so as to avoid end-use controls, or to go without. This pattern of excess capacity in distribution, declining production capacity and excess demand is otherwise all but unknown in American industry at the present time.

The reasons for this state of affairs in natural gas are diverse and complicated. Most analysts familiar with this industry believe, however, that the invocation of price controls at the wellhead in the middle 1950's had effects both on long-term incentives for exploration and on the sales of developed gas supplies. Exploration companies redirected their efforts away from searching for gas in the face of frozen nominal and declining real price in the period 1960-1970. Those that had completed the development process shifted their sales to intrastate buyers, at first because of the extra cost and uncertainties involved in regulation but finally because of higher intrastate prices. At the same time, since gas was held below its market value, there were significant incentives for the substitution of gas for other fuels in industrial use in the producing states.

The structure of existing Federal Power Commission regulation has also strongly affected the allocation of the natural gas that is available. Because regulation is confined to interstate transactions, significant supplies have been reallocated from interstate to home state markets in order to avoid controls and to obtain the higher price that has been available at least since its early 1970's. Except under special provisions exempting sales from the usual controls, only negligible amounts of additional gas have been committed to interstate markets where the supplier had the option of selling within the state. Thus, regulation has operated to reduce the supplies available to those in whose name the Federal Power Commission operates - the residential and industrial consumers in the more populated northern and central sections of the country. This means that some potential consumers of gas must instead buy alternative fuels at many times the price that those who actually consume the gas pay for it. The gas does not go to those for whom it is most valuable.

The Federal Power Commission process has determined who has had the opportunity to receive the reduced interstate supplies. Industrial customers have been curtailed while those residential and commercial customers who have already been attached to the gas system are allowed to receive amounts they expected to receive. Those industrial customers that signed "interruptable" contracts, designed to limit sales to the amount pipelines could deliver on peak days, have been curtailed the most. In effect, FPC procedures have sought to eliminate the queue by choosing to exclude those using gas where there were alternative sources of fuel readily available. Presumably, then, those with the more intensive demands or the greatest willingness to pay have been able to receive the gas.

Unfortunately, for many reasons these goals have not been achieved. Among industrial consumers, those that failed to plan ahead for alternative fuels and thereby did not have alternative systems have been given priority while those with alternative facilities were cut off. Most home customers on the system before the shortage have been allowed to continue consumption at their desired rate, while those coming along later have been prevented from any consumption whatsoever. In effect, allocation by regulation among industrial users and from new to old consumers has resulted in significant departures from best use of resources.

The question is what can be done to ameliorate both the gas shortage and the misallocation of gas under regulation. There is no plan or program that could be offered to Congress for legislative changes that would eliminate the shortage in a year to two. Also, no plan could be offered that would easily redistribute the scarce supplies in an efficient manner, while at the same time preserving the present levels of prices.

Congress recognized in the 1887 Act to Regulate Commerce that it is not the best organization for setting day-to-day transactions prices or allocating scarce supplies among alternative users in an efficient manner. The information requirements are immense for making marginal decisions as to who should receive alternative fuels among pipelines, regions, classes of home consumers and companies. Further politicization of this process can only be expected to add to the waste of resources now already occurring. The solution to the allocation problems lie in obtaining additional supply, so that mandatory controls are unnecessary.

Expecting better regulation from the FPC appears to me to be futile as well. However able and dedicated the FPC staff and leadership, all we can expect is *more* regulation. The question always arises as to whether more or less regulation would work better, when existing regulatory institutions yield perverse results. The Federal Power Commission has already tried virtually all of the step in the direction of more regulation and has failed to elicit increased supply of gas or a more efficient distribution of fuel among potential and existing gas consumers. If the problems of the gas consumer are to be solved, we must move in the direction of reducing the scope and complexity of present controls, so as to add to the market's response on both the supply and demand sides of gas field sales.

Given the proper direction for policy, important questions still must be asked as to the proper rate of decontrol. Should gas prices be allowed to attain an equilibrium level instantaneously, or should controls be phased out over the long-run? Rapid price decontrol would reallocate available volumes of gas to users needing it the most and shorten the period of loss for those consumers who have been unable to obtain the gas they need.

It would also have an appreciable positive effect upon gas supplies discovered and made available to the interstate market. But immediate effects would include substantial price increases for those consumers who have been obtaining this bargain fuel. Their need for time to adjust to higher prices must also be considered.

Within this context we might consider the effect of price increases from decontrol of new supplies of gas that could be expected from the Pearson-Bentsen Bill. With decontrol of all new gas, there would be higher average gas prices for the new supplies that would have been forthcoming without decontrol. But the additional gas supplied to interstate buyers as a result of decontrol would replace higher priced oil imports now used by curtailed gas customers. For reasonable amounts of increased supply of gas, those two effects are roughly comparable but in opposite directions. At the least, the net effect of new gas price decontrol on energy prices as a whole will not be substantial in the next few years. In the long run, as well, a higher gas price would increase exploration making more gas available for production in subsequent years. The additional gas would take pressure off alternate energy sources, lowering their rate of consumption and their prices. It would also permit more productive input combinations, lowering the required number of btu's per dollar of output. These effects reduce sector-by-sector energy consumption, increase general output and thereby add to gross national product. Thus, decontrol in the long run is not inflationary in the economy as a whole, though it would bring increases in gas prices.

To take even a longer view, the period 1975-1985 is likely to be looked upon as one of significant regulatory reform in the Congress. The gas price control activities of the Federal Power Commission are already widely believed to be among the most disruptive and inefficient of those of the independent regulatory commissions. Only rate controls in the Interstate Commerce Commission or rent controls in the City of New York rival the FPC gas price controls in disruptive impact on the supply of goods and services. One cannot consider general plans for developing consistent and coherent regulation in this country without centering attention on some policy for decontrolling new supplies of natural gas. The Pearson-Bentsen mechanism is a good means for attaining some reform along these lines.

STATEMENT OF FRANK G. ZARB
ADMINISTRATOR
FEDERAL ENERGY ADMINISTRATION

Before the

COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
SUBCOMMITTEE ON ENERGY AND POWER
UNITED STATES HOUSE OF REPRESENTATIVES

Friday, January 23, 1976

Mr. Chairman and Members of the Subcommittee, I am pleased to appear before you today to discuss the long-term solution to the natural gas supply problem. Specifically, I have been asked to comment on four legislative proposals which address the issues of price and availability of natural gas in the future -- Title II of S. 2310, introduced by Senators Pearson and Bentsen and passed by the Senate in amended form on October 22 by a 58-32 vote; H.R. 11265, introduced by Representative Krueger; H.R. 9159, introduced by Representative Fraser; and H.R. 11047 introduced by Representative Brown of Ohio.

Before I discuss the provisions of these bills, I would like to say again, as the Administration has said many times before, that it is extremely important to take immediate action on this vital issue. With each day that passes without Congressional action on the deregulation issue, this nation's natural gas supply outlook worsens. We believe the Congress's decision on this issue will largely determine whether this nation will face a coming decade of adequate natural gas supply or increasingly disruptive shortages. Because legislative action on natural gas wellhead price deregulation has been deferred far too long, the nation now

FACES MOUNTING SHORTAGES OF NATURAL GAS.

AMERICA'S NATURAL GAS PRODUCTION PEAKED IN 1973 AND IS NOW DECLINING FASTER THAN OUR DOMESTIC OIL PRODUCTION. SINCE 1968, OUR HOMES, BUSINESSES AND INDUSTRIES HAVE BEEN CONSUMING MORE NATURAL GAS EACH YEAR THAN OUR PRODUCERS HAVE BEEN ADDING TO RESERVES. CURRENT PROVED RESERVES, EXCLUDING ALASKA, NOW STAND AT 205 TRILLION CUBIC FEET, THE LOWEST LEVEL SINCE 1952. NATURAL GAS CURTAILMENTS WHICH FIRST APPEARED ON THE NATIONAL SCENE SIX YEARS AGO, HAVE NOW GROWN INTO A SERIOUS NATIONAL ENERGY PROBLEM. IN 1970, INTERSTATE PIPELINE CURTAILMENTS WERE 0.1 TCF, OR LESS THAN ONE PERCENT OF CONSUMPTION, AND A NORMALLY COLD WINTER THIS YEAR COULD HAVE INCREASED ANNUAL CURTAILMENTS TO AS MUCH AS 2.9 TCF, OR 15 PERCENT OF DELIVERY TO END USERS.

AS MEMBERS OF THIS COMMITTEE ARE AWARE, INTERSTATE PIPELINE CURTAILMENTS ARE MERELY A ROUGH ESTIMATE OF THE MEASURE OF THE NATURAL GAS SUPPLY PROBLEM. TO OBTAIN A MORE ACCURATE VIEW OF THE PROBLEM, THE FEDERAL ENERGY ADMINISTRATION (FEA), IN CONJUNCTION WITH THE FEDERAL POWER COMMISSION (FPC) CONDUCTED A DETAILED SURVEY LAST SUMMER OF 1700 NATURAL GAS COMPANIES IN THE NATION WHICH DELIVER GAS TO END USE CUSTOMERS.

FEA's latest update of this survey data shows curtailments by distributors in those 21 key states at 1.03 Tcf for the current heating season. This is 140 Billion cubic feet greater than last winter. Nationwide, the gas supply outlook has improved from earlier projections, largely due to the warm, dry weather the nation experienced in November and early December which reduced demand for natural gas, propane and fuel oil. Emergency sales of natural gas permitted under FPC regulations have also helped by redistributing gas supplies from surplus to shortage areas.

But even with this improvement, the long-range trend is toward increasing curtailment, with our only protection from potential economic disruption this winter and next being a continuation of reduced demand due to warm weather. Earlier this month, a severe coldspell in several states resulted in temporary industrial shut-downs and school closings. And we are not through the winter yet -- further cold weather can still cause the adverse disruptions from which we have been spared to date. Surely, this nation must not tolerate a situation where the continued availability of so vital a fuel as natural gas must depend on the vagaries of the weather.

Production of natural gas peaked in 1973 at 22.6 Tcf and declined by approximately 5 percent in 1974 to 21.6 Tcf. According to preliminary Bureau of Mines and FEA estimates for 1975, production is estimated to have declined at a rate of close to 7 percent. This situation could jeopardize our continued economic recovery and future economic vitality. Therefore, the decrease in domestic supply from 22.6 Tcf in 1973 to 21.6 Tcf in 1974 is equivalent to 500,000 barrels of oil per day, a totally unacceptable increased dependence upon non-domestic sources. And we see a worse deterioration in our 1975 preliminary figures.

In his State of the Union message one year ago, President Ford proposed the deregulation of new natural gas as a long-range solution to our natural gas problem. We believed then, and we still believe today, that deregulation can improve the natural gas outlook in three significant ways: First, by providing the economic incentive for producers to develop new and additional gas supplies from the outer continental shelf (OCS), from Alaska and from tighter, deeper onshore formations. Secondly, by encouraging more efficient natural gas usage, as the price is allowed over time to reflect the true economic value of this clean-burning fuel. And, thirdly, by gradually eliminating the current price disparity between the interstate and intrastate gas markets which now distorts our natural gas distribution.

Let me give you an example of the benefits of deregulation. In preliminary figures from a Project Independence update, FEA projects, for 1985, gross marketed production of 17.9 Tcf under current regulations and 22.3 Tcf under deregulation, and net marketed production of 15.9 and 20.0 Tcf respectively. That difference is the equivalent of over 2 million barrels of oil per day. Admittedly, there would be a slightly higher fuel bill to present day gas users under deregulation but that would be more than offset by the greatly increased domestic gas production and reduced need of imports.

Another example is the effect deregulation would have on the interstate market. Without deregulation, we project for 1985 9.3 Tcf in the intrastate market and 6.6 Tcf in the interstate market. However, with deregulation the shift is dramatic: 7.9 Tcf in the intrastate and 12.1 Tcf in the interstate market; an increase of 5.5 Tcf in the interstate market.

While a major synthetic fuels program can increase long-term gas supplies somewhat, the decrease in production we have seen since 1973 is projected to continue unless action is taken both for conservation and to provide needed incentives for additional exploration, development and production.

The Administration's concern with growing natural gas curtailments prompted President Ford to order the creation of a special interagency natural gas task force under the direction of the FEA. The task force is responsible for coordinating the Federal Government's activities relating to gas shortages. Since its inception last September, it has supervised the collection and publication of data on natural gas distributor curtailments, providing data assistance to state energy offices. It has also put into place a network of regional representatives to monitor the gas supply outlook at the local level and report back to Washington any problems which may develop. In addition, the task force has worked closely with the FPC, providing information on alternate fuels, and with the Department of Commerce in their industrial conservation effort. However, even with our efforts to encourage conservation and consumers' improving attitudes towards doing so, the problem is far from being solved. Unless Congress acts now, this nation can anticipate an unending succession of winters marked by ever-increasing shortages and potential economic dislocation.

Clearly, the solution to the problem is the immediate deregulation of the wellhead price of new natural gas. The legislation introduced by Senators Pearson and Bentsen and Representative Krueger illustrate a viable deregulation plan which will turn the tide of increasing shortages and are supported by the Administration.

Title II of S. 2310 as passed by the Senate would deregulate the wellhead price of onshore new natural gas on April 4, 1976. New natural gas is defined as gas first dedicated to interstate commerce on or after January 1, 1975 or gas produced from a reservoir discovered or extended on or after January 1, 1975. Offshore gas would be deregulated on January 1, 1981. In the interim, its price is set at a royalty crude oil equivalency until the FPC establishes a national ceiling rate.

Regarding gas from expired interstate contracts, the FPC would establish, and revise biennially, a national ceiling rate. Therefore, while such gas would not be deregulated, it would be treated in a special manner.

S. 2310 would also amend the Natural Gas Act by adding eight new sections, including Section 25 which would essentially establish a curtailment order of priorities which

THE FPC MUST PUT INTO EFFECT, WITH PRIORITY ONE FOR RESIDENTIAL AND SMALL USERS AND PUBLIC HEALTH AND SAFETY USERS; PRIORITY TWO FOR ESSENTIAL AGRICULTURAL USERS, AND PRIORITY THREE FOR ESSENTIAL INDUSTRIAL USERS (I.E., PROCESS AND FEEDSTOCK USERS). THESE PRIORITIES WOULD BE ESTABLISHED WITHOUT REGARD TO WHETHER THE UNDERLYING CONTRACT IS FIRM OR INTERRUPTIBLE.

UNDER SECTION 25(A) THE SECRETARY OF AGRICULTURE WOULD DETERMINE THE AGRICULTURAL PURPOSES FOR WHICH NATURAL GAS IS ESSENTIAL, AND CERTIFY TO THE FEDERAL POWER COMMISSION THE AMOUNT OF NATURAL GAS NECESSARY TO MEET FULL FOOD AND FIBER PRODUCTION REQUIREMENTS. THE ADMINISTRATION BELIEVES THAT ESSENTIAL AGRICULTURAL NEEDS DESERVE PRIORITY, BUT WE DO NOT FEEL THAT SECTION 25(A) IS THE PROPER VEHICLE TO ASSURE THAT THESE NEEDS ARE MET. HOWEVER, WITH MINOR TECHNICAL AMENDMENTS, THIS PROVISION CAN BE MADE WORKABLE.

A NEW SECTION 26 WOULD SUBJECT SYNTHETIC NATURAL GAS (SNG) PLANTS, THE PERSONS OWNING OR OPERATING THEM, AND SNG SALES AND TRANSPORTATION TO FPC JURISDICTION. THIS REPRESENTS AN EXPANSION OF EXISTING AUTHORITIES, WHICH IS UNNECESSARY ADDED REGULATION. THEREFORE, WE WOULD PREFER TO SEE THIS SECTION REMOVED.

Section 27 mandates FPC prohibition of boiler fuel use of natural gas not contracted for prior to January 1, 1975, unless alternative fuels -- other than oil or propane -- are unavailable or cannot be utilized at that time. It requires termination of boiler fuel use of natural gas contracted for before January 1, 1975, at the time of contract expiration or in 12 years, whichever is earlier, subject to the same limitations stated above. The Administration strongly opposes these long-term FPC prohibition authorities since FEA already has similar authorities under the Energy Supply and Environmental Coordination Act (ESECA). It seems incongruous that FPC should now be given authority to prohibit boiler fuel use when FEA has already been given that authority in other legislation.

Another part of Section 27 would require the Administrator of FEA to prohibit residential gas usage which he determines to be solely for ornamental or decorative purposes. While this type of conservation activity should be encouraged, we feel it is a matter which should only be made mandatory at the discretion of individual states and not by Federal

FIAT.

S. 2310 ADDS A SECTION 28 TO THE NATURAL GAS ACT WHICH WOULD REQUIRE ALL PIPELINES TO FILE SEPARATE TARIFFS WITH RESPECT TO OLD AND NEW NATURAL GAS AND REQUIRES DISTRIBUTING COMPANIES TO PROVIDE LOWER PRICED OLD GAS TO RESIDENTIAL AND SMALL USERS ON A PRIORITY BASIS. WHILE ON THE FACE OF IT, THIS INCREMENTAL PRICING PROVISION APPEARS TO BENEFIT RESIDENTIAL CONSUMERS, IN FACT, IT WILL PLACE THE BURDEN OF HIGHER COSTS FOR GOODS AND SERVICES ON ALL CONSUMERS -- WHETHER GAS USERS OR NOT -- TO SUPPLEMENT LOWER FUEL COSTS FOR HOMEOWNERS WHO DO USE GAS. WE MUST REALIZE THAT WE ARE NO LONGER IN THE ERA OF CHEAP, ABUNDANT ENERGY, AND EVERYONE MUST BE PREPARED TO PAY THE ADDITIONAL COSTS. IT WOULD BE WRONG TO SINGLE OUT ONE SECTOR -- GAS-CONSUMING HOMEOWNERS -- FOR FAVORABLE TREATMENT AND CAUSE ALL OTHER CONSUMERS TO PAY MORE THAN THEIR SHARE. FINALLY, WE ARE CONCERNED THAT SUCH A PROVISION WOULD HAVE A DELETERIOUS EFFECT UPON SNG INVESTMENTS AT THIS TIME, AND WOULD ALSO REMOVE INCENTIVES FOR FURTHER RESIDENTIAL CONSERVATION.

THE BILL WOULD ALSO REQUIRE THE DEPARTMENT OF THE INTERIOR TO SET MAXIMUM EFFICIENT RATE PRODUCTION STANDARDS for all fields on Federal lands other than Naval Petroleum Reserves. Since this provision is already covered by the Energy Policy and Conservation Act, it seems unnecessary to include it in this bill as well.

H.R. 11265, introduced by Representative Krueger, is similar to S. 2310 in that it provides for immediate deregulation of onshore gas, with offshore gas to be deregulated on January 1, 1981. "New natural gas" is defined in the bill as gas first dedicated to interstate commerce on or after January 1, 1975; produced from wells commenced after that date; or continued in interstate commerce upon contract expiration. In that regard, the Krueger bill's inclusion of gas from expired contracts in the definition of new gas is different from S. 2310.

As in S. 2310, the Krueger bill would require the FPC to establish a national ceiling rate for new OCS natural gas through December 31, 1980. From enactment to the establishment of that ceiling price, the United States Geological Survey crude oil equivalent valuation would apply, and on January 1, 1981, the ceiling would be lifted for all new OCS gas.

The Krueger bill is also similar to S. 2310 regarding agricultural priorities and boiler fuel prohibitions which I have already discussed. I believe that the Krueger bill will improve our natural gas situation and, with the exception of the boiler fuel section, I urge its enactment. I understand that your staff has certain technical problems with the bill and my staff has made known its desire to meet with them to discuss those problems.

In regard to Representative Brown's bill, H.R. 11047 -- while we believe the bill would be an improvement over the present situation, the Administration, and I believe Mr. Brown would agree, feels that H.R. 11265 is the more effective vehicle to meet this nation's natural gas needs. The bill would require the FPC to designate distressed and curtailed interstate pipelines. From enactment through April 15, 1976, distressed pipelines would be empowered to buy new gas at unregulated prices. From April 16, 1976 through April 15, 1977, both distressed and curtailed pipelines would be able to purchase unregulated new natural gas; and from April 16, 1977 through the end of the supply

PERIOD (7 YEARS TOTAL) INTERSTATE PIPELINES WITH A CURTAILMENT PLAN ON FILE WITH THE FPC WOULD BE ABLE TO PURCHASE NEW GAS AT UNREGULATED PRICES. WHILE THIS BILL WOULD BRING RELIEF TO CURTAILED AND DISTRESSED PIPELINES, AND WOULD GIVE A TEMPORARY IMPETUS TO OUR SUPPLY SITUATION, IT DOES NOT PROVIDE A PERMANENT SOLUTION TO THE PROBLEM.

H.R. 9159, INTRODUCED BY REPRESENTATIVE FRASER, IS COMPLETELY UNACCEPTABLE TO THE ADMINISTRATION. RATHER THAN DEREGULATING NEW NATURAL GAS PRICES, THIS BILL NOT ONLY CONTINUES PRICE REGULATION IN THE INTERSTATE MARKET BUT ALSO CALLS FOR EXTENSION OF REGULATION TO THE INTRASTATE MARKET. INSTEAD OF ALLOWING THE WELLHEAD PRICE OF NEW NATURAL GAS TO BE DEREGULATED, THE BILL WOULD CAP THE PRICE FOR INTER AND INTRASTATE NEW GAS AT A BASE PRICE OF 60¢ PER MCF. AS YOU KNOW, WE STRONGLY BELIEVE THAT ANY PRICE CAP WOULD BE A DETERRENT TO PRODUCTION. HOWEVER, THIS PARTICULARLY LOW CAP WOULD STYMIE ALL EXPLORATION AND DEVELOPMENT AND CAUSE A STEADY DECLINE IN EXISTING SUPPLIES. IN ADDITION, OUR DEPENDENCE UPON FOREIGN OIL WOULD INCREASE AS WE WOULD HAVE TO IMPORT OIL TO MAKE UP FOR THE UNAVAILABLE GAS. THE COSTS OF IMPORTED OIL TO REPLACE NATURAL GAS IS QUITE EXPENSIVE

AND MANY CONSUMERS WILL BE IN A WORSE POSITION WITH SO CALLED "LOWER GAS PRICES" THAN THEY WOULD BE UNDER DEREGULATION.

THERE ARE MANY OTHER OBJECTIONABLE PORTIONS OF THIS BILL SUCH AS THE INCREMENTAL PRICING PROVISION, ADDITIONAL PRODUCTION REQUIREMENTS, MANDATORY INTERPIPELINE CONNECTIONS DURING EMERGENCY PERIODS, FPC JURISDICTION OVER SNG, AND FPC JURISDICTION OVER BOILER FUEL CONVERSIONS. I FEEL STRONGLY THAT THIS BILL WOULD BE SERIOUSLY COUNTERPRODUCTIVE TO MEETING THE NATION'S ENERGY NEEDS AND WILL PROVIDE A MORE DETAILED ANALYSIS OF ITS EFFECTS UPON THE REQUEST OF THE COMMITTEE.

LET ME SUMMARIZE THE ADMINISTRATION'S POSITION ON THE PENDING LONG-TERM LEGISLATION WHICH I HAVE DISCUSSED. THE SENATE-PASSED BILL IS CERTAINLY A STEP IN THE RIGHT DIRECTION. WITH THE CHANGES WHICH I HAVE MENTIONED, I WOULD RECOMMEND ITS ENACTMENT. THE KRUEGER BILL IS SIMILAR TO THE SENATE BILL BUT ELIMINATES MANY OF THE SENATE BILL'S OBJECTIONABLE FEATURES. I BELIEVE IT IS VERY CLOSE TO A BILL WHICH I COULD RECOMMEND TO THE PRESIDENT. THE 7-YEAR BILL IS CLEARLY A STOP-GAP EFFORT, SUPERIOR TO DOING NOTHING, BUT INFERIOR TO OTHER POSSIBILITIES WE HAVE DISCUSSED.

THAT CONCLUDES MY REMARKS. I WOULD BE HAPPY TO ANSWER ANY QUESTIONS.

NATURAL GAS
FACTS AND FIGURES FOR 1974
TECHNICAL REPORT 76-1

January 22, 1976

FEDERAL ENERGY ADMINISTRATION
OFFICE OF THE DEPUTY ASSISTANT ADMINISTRATOR
FOR DATA AND ANALYSIS
OFFICE OF OIL AND GAS ANALYSIS

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This paper was prepared by the following people in the Office of Oil and Gas:

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Natural Gas Facts and Figures for 1974*

This report shows the sources and dispostion of natural gas volumes in the United States during 1974.

A schematic diagram provides a general picture of how gas flows from the supply source to the end-use customer.

Information is provided on average wellhead interstate and intrastate gas prices, city gate prices (wholesale) and end user prices (retail).

A description of the several types of sales not regulated by the Federal Power Commission is also provided.

Table 1
BUREAU OF MINES TERMINOLOGY ASSOCIATED WITH NATURAL GAS PRODUCTION AND 1974 VOLUMES (MCF)

1.)	Gross withdrawals	22,849,793	- Gas withdrawn from oil and gas wells
	Minus		
2.)	Repressuring	1,079,890	- Gas injected into the reservoir in order to increase recovery
	Equals		
3.)	Net withdrawals	21,769,903	-
	Minus		
4.)	Vented and Flared	169,381	- Includes direct losses on producing properties and residue blown into the air.
	Equals		
5.)	Marketed production	21,600,522	- Volume delivered to processing plants, sold to pipelines or sold directly to end-use customers by producers.
	Plus		
6.)	Withdrawals from storage	1,700,546	- Gas withdrawn from storage reservoirs.
	Plus		
7.)	Imports	959,284	-
	Equals		
8.)	Total Supply	24,260,352	
	Minus		
9.)	Lease and Plant Fuel	1,477,386	- Fuel used on leases or in processing plants
	Minus		
10.)	Extraction losses	887,490	- Volume shrinkage resulting from extraction of natural gas liquids
	Minus		
11.)	Transmission losses	288,731	- Gas lost or unaccounted for in the transmission process
	Minus		
12.)	Pipeline fuel	668,792	- Fuel used by pipeline for compressors, etc.
	Minus		
13.)	Injected into Storage	1,784,209	- Gas injected into storage reservoirs
	Minus		
14.)	Exports	76,789	-
	Equals		
15.)	Deliveries to consumers	19,076,955	

In 1974, 24.3 TCF of gas supply was available, of which 79 percent was delivered for end-use consumption. The remaining 21 percent was used for exports, used for repressuring, extraction of natural gas liquids, fuel, or was reported as lost and unaccounted for during transmission.

DISTRIBUTION OF NATURAL GAS: 1974

In 1974 the 19.08 TCF of natural gas reported as delivered was distributed as follows:

TABLE 2
1974 End-use Distributions of Natural Gas (TCF)

Total	Residential	Commercial	Industrial	Electric Utilities	Other
19.08	4.79	2.26	8.31	3.43	0.29

Other: The category other is defined as deliveries to municipalities, public authorities, street lighting, etc.

NATURAL GAS TRANSMISSION SYSTEM

Figures 1 traces the flow of natural gas from the sources of supply to end-use deliveries.

INTERSTATE AND INTRASTATE PRICES

Most of the contracts for the purchase of gas by interstate pipelines from producers are for terms of 15 to 20 years. The price distribution of old interstate contracts as of 1972 (latest year available) are as follows.

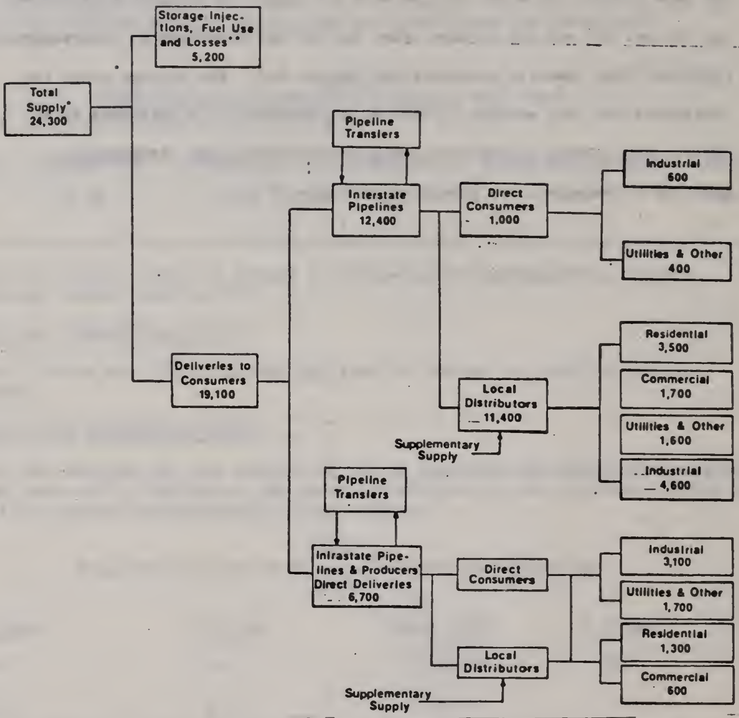
TABLE 3
Price Distribution of Old Gas Contracts-Interstate Gas
(1972)

Price ¢/MCF	% of Gas	Price ¢/MCF	% of Gas
Over 31	5.3	17.01-19	17.6
29.01-31	1.2	15.01-17	9.2
27.01-29	4.7	13.01-15	4.7
25.01-27	10.0	11.01-13	2.7
23.01-25	3.7	9.01-11	.03
21.01-23	21.3	below 9	.01
19.01-21	19.3		

Interstate gas volumes are classified as old gas or new gas by the FPC for producer price regulation purposes. In 1974, the ceiling prices for old gas were still on an area basis and ranged from 11¢ per Mcf to 28¢ per Mcf, the base ceiling price for new gas sold for resale to interstate pipelines was 42¢ per Mcf and the average price for all gas purchased by interstate pipelines from domestic producers was 27¢ per Mcf. The average price for intrastate gas, not subject to the FPC's jurisdiction is estimated to be 37¢ per Mcf. These prices along with transportation and distribution mark-ups to end-users are presented in Figure 2.

Figure I

Overview — U. S. Natural Gas System (Bcf)



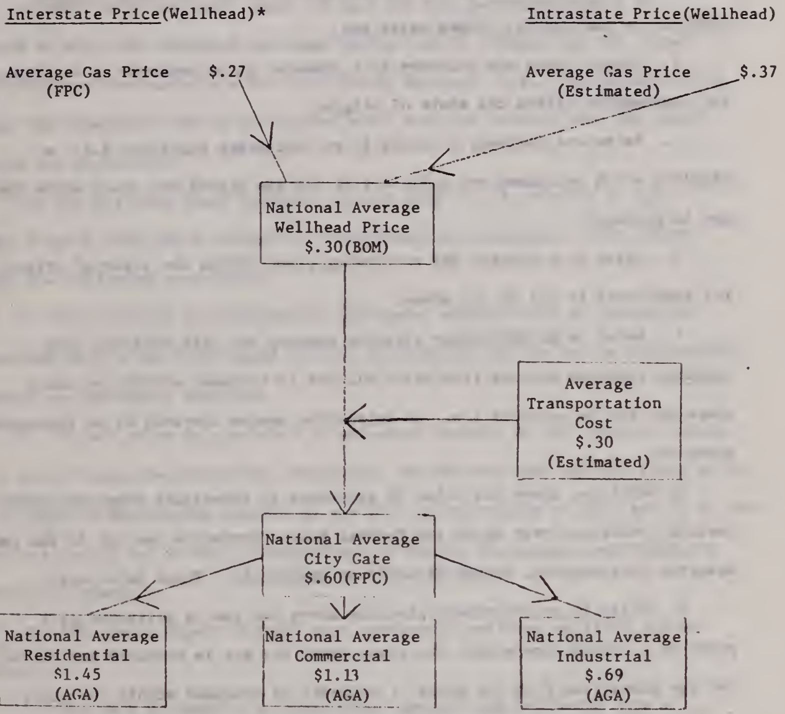
* Supply includes U.S. marketed production, withdrawals from storage, and imports.

** Gas for such purposes as lease and plant fuel, pipeline compressor fuel, extraction loss, and transmission losses.

Source: Based primarily on data from "Natural Gas Production and Consumption: 1974" (Washington, DC: Bureau of Mines, Mineral Industry Surveys, 1975).

Note: Divisions between interstate and intrastate volumes are estimated.

FIGURE II
1974 PRICES OF NATURAL GAS
AT VARIOUS STAGES OF THE PRODUCTION
TRANSPORTATION AND DISTRIBUTION SYSTEM
($/MCF)


Interstate Price(Wellhead)*
Intrastate Price(Wellhead)
Average Gas Price (FPC) $.27
Average Gas Price (Estimated) $.37
National Average Wellhead Price $.30(BOM)
Average Transportation Cost $.30 (Estimated)
National Average City Gate $.60(FPC)
National Average Residential $1.45 (AGA)
National Average Commercial $1.13 (AGA)
National Average Industrial $.69 (AGA)

*Note: In 1974 the national base ceiling price for natural gas regulated by FPC was 42¢/Mcf. Old gas was regulated on an area price ceiling basis with rates ranging from 11¢ (Oklahoma Other Area) to 28¢ (Appalachian area). The FPC reports that the weighted average initial price, inclusive of adjustments, for new intrastate contracts for the period 1-1-74 to 1-1-75 was 92¢ per Mcf.

Description of Types of Sales Not Regulated by FPC

There are several types of sales by producers where it is recognized that the Federal Power Commission has no jurisdiction. Such sales do not require FPC certification nor is the producer's price controlled, either directly or indirectly. These sales are:

1. Direct sales and delivery by a producer to an end-user or distributor for consumption within the state of origin.

2. Sales and delivery directly to an intrastate pipeline, i.e., a pipeline which purchases and sells all of its gas within the state where the gas is produced.

3. Sales to a natural gas processing plant within the state of origin for redelivery to (1) or (2) above.

4. Sales to an interstate pipeline company but with delivery into separate pipeline systems from which all gas is consumed within the state where the gas is produced i.e., an intrastate system operated by an interstate pipeline.

In addition, there are sales by producers to interstate pipelines under certain conditions over which the Federal Power Commission has not in the past asserted jurisdiction, either directly or indirectly. These sales are:

5. Sales to an interstate pipeline where the gas is delivered at a point on a branch line within the state where the gas is produced and all of the gas downstream from the point of delivery is consumed within the state.

6. Sales to an interstate pipeline where the interstate pipeline terminates in the state where the gas is produced and the gas picked up in the state is consumed in the same state i.e., the pipeline downstream of the point where this gas is purchased does not cross the state line.

The regulatory status of sales under these conditions is currently under review by the Commission in several individual pipeline cases. The pipelines resell such gas under the terms of their FPC Tariffs, i.e., at FPC regulated prices. The question before the Commission is whether the full unregulated prices paid under (5) and (6) type purchases should be rolled in with the regulated purchased gas prices in determining the proper purchased gas cost allowance for rate making purposes, e.g., incremental rates. Thus, the Commission may in the future exert indirect control over the field prices for such sales.

The FPC may also exert indirect control over the field price of gas under certain conditions through its certification procedures. This occurs under the following conditions:

7. Direct sales by producers to end-users, distributors or intrastate pipelines within the state where the gas is produced and the gas is transported through an interstate pipeline.

8. Direct sales by producers to end-users outside of the state of origin.

Under these transportation conditions, the FPC may consider the field price of the gas in determining whether or not the transportation of such gas is in the public interest and whether a Certificate of Public Convenience and Necessity should be issued.

The FPC exerts direct control over producer's wellhead or field prices where:

9. The sale is made to an interstate pipeline and delivered into a system from which all or any portion of the gas in the system is transported and sold outside of the state of origin.

10. The sale or delivery of the gas is made to a natural gas processing plant or to another producer for resale or redelivery to an interstate pipeline as in (9) above.

The varying degree of control exerted by the FPC upon producer gas prices is roughly rèflected in the statistics collected by the FPC. The Commission does not collect nor publish data pertaining to the intrastate sales by producers that are considered non-jurisdictional (1, 2 and 3 type sales) except in limited and infrequent cases, e.g., reports of intrastate contracts by interstate companies. Intrastate sales to an interstate pipeline, whether definitely intrastate (Type 4) or "questionably" intrastate (Types 5 and 6), are collected and included in the published FPC statistics. The volumes involved are not generally reported separately but instead are included in the total purchased gas and sales figures. Sales of the "indirectly controlled" (Types 7 and 8) appear in the FPC statistics under the category "Gas Transported For Others."

NATURAL GAS DEREGULATION ANALYSIS

TECHNICAL REPORT

FEA 76-3

JANUARY 23, 1976

OFFICE OF POLICY AND ANALYSIS
FEDERAL ENERGY ADMINISTRATION

EXECUTIVE SUMMARY

Deregulation of natural gas yields higher prices and higher prices bring forth higher production. Current legislation has artifically created two separate but interdependent markets for natural gas. Without deregulation, the interstate consumers of natural gas will bear a disproportionate share of the burden of declining production. Under present regulation the absolute quantity of natural gas consumption in the interstate market would decline by 43 percent while the quantity available to intrastate customers would increase by 29 percent.

Projected Natural Gas Production

If natural gas wellhead regulation continues at current real prices, total domestic natural gas production would decline from the 1974 level of 21.6 TCF to less than 18 TCF by 1985. If regulations are combined with a national price ceiling of $1/MCF, production would reduce to less than 16 TCF. However, if new contracts are deregulated, FEA estimates that 1985 production could rise to 22.3 TCF. Forecasts of domestic production and sales to the interstate market under several legislative alternatives are summarized in Figure 1. These various bills and the associated production estimates imply different costs to the consumers, create different regional imbalances, and can affect the oil import position of the United States. To the extent that gas shortages are translated into oil consumption, oil imports will increase. The difference between deregulation and continued regulation could be as much as 2 million barrels per day.

Cost of Deregulation

Short Term: While the long-run impacts of natural gas deregulation are important, the short-run effects in 1976 include higher costs. For example, FEA estimates the 1976 impact of the Pearson-Bentsen bill to be a total cost of $5 billion to $6 billion.

Long-Term: FEA estimates of the long-run impact of gas deregulation on residential fuel bills are computed for several of the proposed legislative actions pending before Congress. Figure 2 shows the 1980 and 1985 Annual Residential Fuel Cost for several of the pending bills.

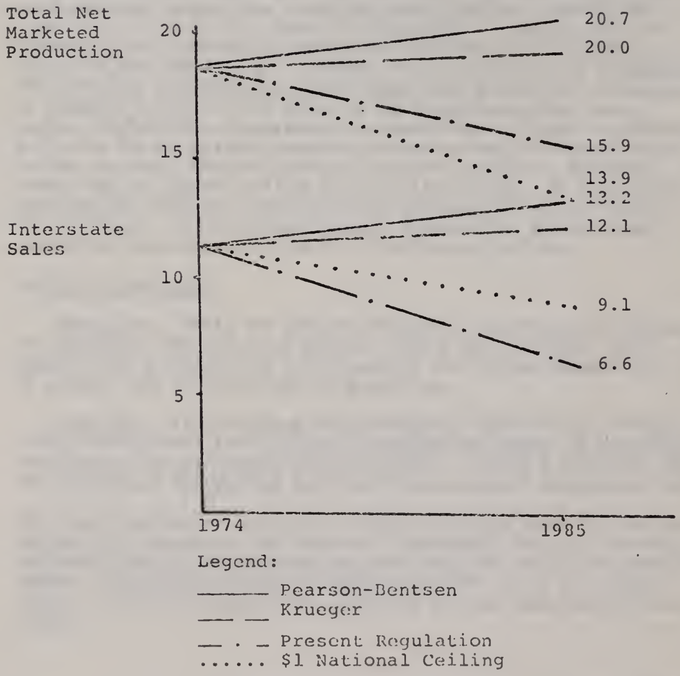
The Annual Residential Fuel Cost in 1985 is lowest under the Pearson-Bentsen Bill because of the impact of incremental pricing, lowering the first cost to the consumer but increasing the cost to the industrial sector. To the extent that increased industrial costs are passed through, the total costs to all consumers will be comparable to the other bills.

Interstate and Intrastate Sales

The various legislative options provide for markedly different long-run impacts on the interstate market. The current regulations have contributed to a reduction of interstate sales from over 13 TCF to 11.6 TCF in 1974. This reduced supply has caused an increase in the estimates of gas curtailments and the extension of supply interruptions to higher priority users. Continuation of current regulations would reduce interstate sales to less than 7 TCF in 1985 while increasing intrastate sales from 7.2 TCF to 9.3 TCF. The alternative deregulation proposals will maintain or increase sales to the interstate market without reducing the levels in intrastate sales.

FIGURE 1

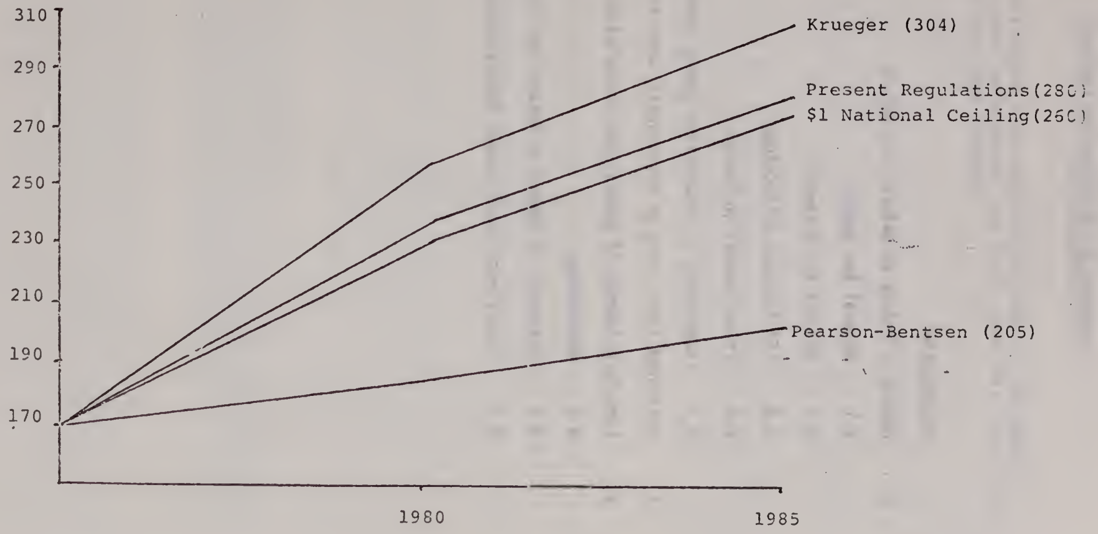
NET MARKETED NATURAL GAS PRODUCTION UNDER VARIOUS POLICIES*: TOTAL PRODUCTION AND INTERSTATE (TCF)



* Intrastate sales are the difference between total net marketed production and interstate sales.

FIGURE 2

ANNUAL RESIDENTIAL FUEL BILL
(CONSTANT 1975 $/YR)



NATURAL GAS DEREGULATION ANALYSIS

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NATURAL GAS DEREGULATION ANALYSIS

1. Introduction

This technical paper presents a quantitative analysis of issues associated with natural gas deregulation. The major analytical topics addressed are the impact of prices on natural gas supply, estimates of the impact of current proposed natural gas deregulation on the total residential fuel bill and the residential natural gas fuel bill, and estimates of the total cost of deregulation to the consumer in 1976. The impact estimates include only gas consumption from domestic sources, excluding liquified natural gas, synthetic fuels and imported natural gas. Thus, total gas consumption from all sources will be above that reported in this paper.

This paper is the latest in a series of preliminary documents addressing this subject. The series of revisions have evolved with the improvements in the underlying data base and methodology. This is the first revision to fully incorporate the estimates developed in conjunction with the revision of the Project Independence studies.

2. Impact of prices on Natural Gas Supply

Prior to the preparation of the first Project Independence studies, the major sources of information regarding the potential supply of natural gas were found in the forecasts of the Federal Power Commission, the estimates of the Natural Gas Potential Supply Committee, the TERA Modeling System of the American Gas Association, the MacAvoy-Pindyck Model developed by researchers at MIT, and the oil and gas model of the National Petroleum Council. The Federal Power Commission forecasts and those of the Natural Gas Supply Committee did not derive from formal models and the TERA and MacAvoy-Pindyck system did not contain the necessary regional detail available in the National Petroleum Council Model. Therefore, the Federal Energy Administration began an effort to modify the National Petroleum Council model to permit integration into the overall Project Independence studies.

The revised supply model produces estimates of natural gas production which recognize the difference in costs and, therefore, prices of producing from reserves of different size and quality. This price sensitivity is essential in evaluating the impacts of fuel competition or in assessing the potential supply results from gas price deregulation.

The revision of estimates for Project Independence is completed within FEA. This section presents estimates of these revised gas supply figures, explains the methodology of development, and compares the FEA forecasts to other estimates that are available. These figures indicate the importance of prices in determining potential gas supply and indicate the impacts of continuation of price regulation below market clearing levels. The effects of alternative regulatory structures are discussed in more detail in section 3.

The prices discussed in this section refer to new gas prices at the wellhead. Since old contract prices can continue in effect, the costs to the consumer could be correspondingly lower.

2.1 Natural Gas Supply

If new natural gas prices are deregulated and real uncontrolled oil prices remain at their current level, FEA estimates that total domestic production will be 22.3 TCF in 1985 at a wellhead price of $2.13. If full deregulation does not occur and new natural gas prices are set at $1.00/MCF at the wellhead, this supply estimate could drop to 15.8 TCF. The sensitivity of these aggregate estimates are displayed by separating the discussion into the contribution of total supply that comes from gas wells (non-associated gas) and that which comes from wells that primarily produce oil (associated gas). The historical production of non-associated and associated natural gas appear in Table 1.

Table 1

Historical Production of Associated and Non-Associated Production (TCF)

	Associated*	Non-Associated*
1966 **	4.6	12.9
1967	4.7	13.6
1968	4.6	14.7
1969	4.8	15.9
1970	4.8	17.1
1971	5.0	17.1
1972	4.8	17.7
1973	4.8	17.8
1974	4.2	17.1

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*Preliminary net production

**Not available prior to 1966

Source: Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1974. Volume 29, May 1975. American Gas Association

Previous to 1966, separate production estimates for non-associated and associated gas were not reported. However, estimates of additions to reserves to proved reserves are reported and appear in Table 2. This table shows that in 1967, when FPC price regulations became a constraint (or binding), proved reserves peaked and have been declining since then. Except for 1970, additions to reserves have been declining since 1967. It is felt that the decline since 1967 in both additions to reserves and proved reserves is a result of the FPC price controls which while implemented in 1954 revised in 1961 and became a binding constraint in the 1966-1967 period.

Non-Associated Gas

The FEA model and assumptions produce estimates of natural gas production for 12 oil and gas producing regions. The actual production from these regions depends upon a number of factors including demand, relative transportation costs, leasing rates, and uncertainties about the total available supply of gas. Non-associated gas production in 1974 was 17.1 TCF. Under the FEA business as usual conditions (BAU), the national production possibilities as a function of price are depicted in Table 3. Non-Associated production at the lowest price examined, $1.00/MCF, is 13.3 TCF in 1985. At the highest price, $2.80/MCF, the figure rises to 18.1 TCF. In 1990, the range is even greater, going from 8.8 TCF to 17.9 TCF for $1.00 and $2.80 respectively.

Table 3 indicates the effects of depletion and the changes in production over time as a function of price. This phenomenon is depicted in more detail for selected prices in Figure 1.

Table 2

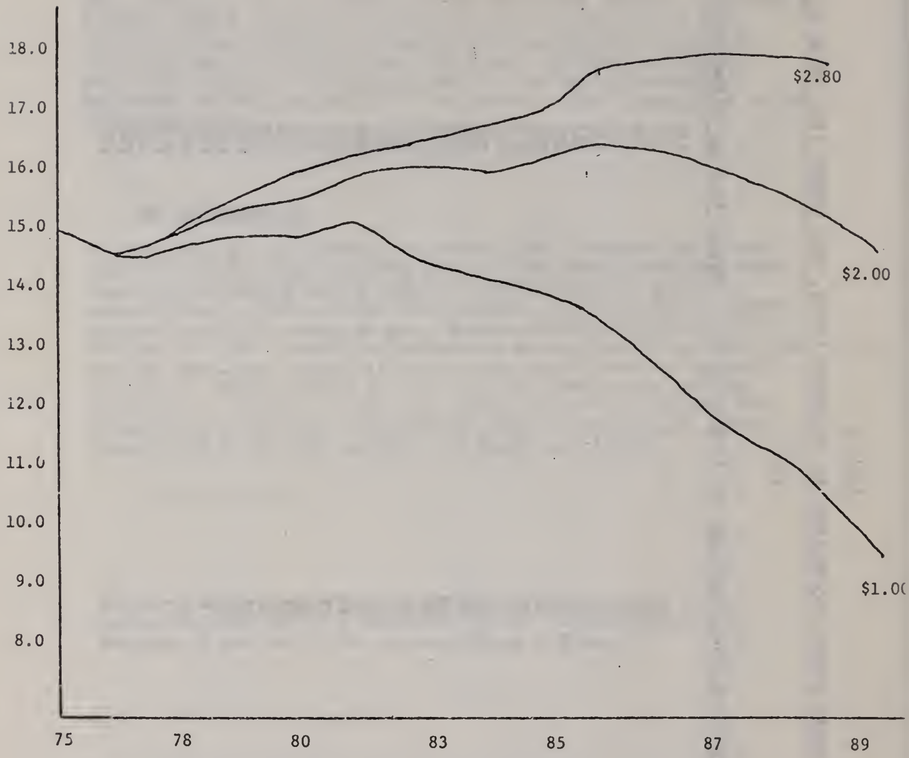
ANNUAL ESTIMATES OF PROVED NATURAL GAS RESERVES IN THE UNITED STATES, 1945 THROUGH 1974, TOTAL ALL TYPES

(TCF)

Year	Total of Discoveries, Revisions and Extensions	Proved Reserves at End of Year
1945		146
1946	17	159
1947	10	165
1948	13	172
1949	12	179
1950	11	184
1951	15	192
1952	14	198
1953	20	210
1954	9	210
1955	21	222
1956	24	236
1957	20	245
1958	18	252
1959	20	261
1960	13	262
1961	17	266
1962	19	272
1963	18	276
1964	20	281
1965	21	286
1966	20	289
1967	21	292
1968	13	287
1969	8	275
1970	37	290
1971	9	278
1972	9	266
1973	6	249
1974	8	237

Source: See Table 1

FIGURE 3
NON-ASSOCIATED NATURAL GAS PRODUCTION FROM THE LOWER 48 STATES ANA OCS IN THE BUSINESS-AS-USUAL OUTLOOK



* Interval from 1980 to 1989 fitted on 1980 and 1989 observations for the $1.00 case.

Table 3

Non-Associated Gas Production (TCF) (BAU)

Wellhead Price (1975 $)	1980	1985
$0.60	9.9	5.9
$1.00	15.4	13.3
$1.20	15.6	14.5
$1.40	16.0	15.5
$1.70	16.1	16.1
$2.00	16.2	16.6
$2.20	16.2	16.9
$2.40	16.3	17.3
$2.80	16.5	18.1

Regardless of price the Outer Continental Shelf (OCS) contribution to production is constant in 1980 (3.7 TCF) and in 1985 (4.5 TCF). This special characteristic for the OCS is a temporary phenomonem, applicable over this time frame because of the limitations on leasing. The forecasts with higher leasing rates or for later years show greater OCS production and response to price changes.

The sensitivity of these production estimates to factors other than price have been examined under two separate scenarios other than BAU prepared by FEA. The primary pessimistic or optimistic assumptions are summarized in Table 4

Table 4

Optimistic and Pessimistic Outlook Assumptions

	Pessimistic	BAU	Optimistic
Resource Assessment	USGS "Mean" Minus 36%	USGS "Mean"	USGS "Mean" Plus 36%
OCS Leasing**	18.7 Million Acres	27.7 Million Acres	39.7 Million Acres
Investment Tax Credit	10% through 1977; 7% thereafter	10% through 1977; 7% thereafter	10% throughout

---

*These represent ± one standard deviation around the USGS "statistical" mean.

**Oil leasing not separated from gas leasing here.

These alternate assumptions produce significantly different production estimates, but the basic price sensitivity of the output is preserved. Table 5 indicates the effects of the alternate scenarios on the production estimates for 1985. The difference in production from the pessimistic to the optimistic is 3.9 TCF at $2.00.

Table 5

Non-Associated Gas Production (TCF)
(1985)

Wellhead Price (1975 $)	Pessimistic	BAU	Optimistic
$2.00	15.2	16.6	19.1
$2.80	16.2	18.1	20.9

Associated Gas Production

In addition to the volumes of gas from gas wells, there is a significant contribution of production from wells that are primarily oil wells. In 1974, this amounted to 4.2 TCF. The evaluation of the price sensitivity of associated gas is complicated by the importance of the price of oil and the significant contribution of higher oil production that comes from increased gas prices. Table 4 depicts these effects for 1985 by displaying the business as usual associated gas supply under two assumptions. The first group indicates the associated gas supply if gas and oil prices are assumed to be in approximate BTU equilibrium for the consumer. This indicates that the supply of associated gas would rise from 2.54 TCF at $1.00/MCF to 4.19 TCF at $2.00/MCF in 1985.

Table 6

Associated Gas (TCF)

Wellhead Price (1975 $)	Production With Oil Prices at BTU Equilibrium		Gas and Incremental Oil at $13	
	1980	1985	1980	1985
$1.00	2.31	2.54	3.45	3.80
$2.00	2.49	4.19	3.92	6.59

The second group depicts the gas equivalent if prices of uncontrolled oil maintain their current real level and the increased oil production due to gas price changes is included on a BTU basis. This indicates that as prices range from \$1.00 to \$2.00 the production of natural gas or natural gas equivalents could increase from 2.54 TCF to 4.19 TCF or from 3.80 TCF to 6.59 TCF in 1985, depending upon corresponding assumptions about the world price of oil.

Special Regions

In addition to the associated and non-associated gas production estimates of the FEA model, there is a contribution from areas known as special regions (Alaska, tight gas) which is estimated separately. The 1985 estimated supply from special regions is .17 TCF at under \$1.00 and .46 TCF over \$1.10.

Price Sensitivity

The estimates for associated and non-associated production show a significant response to higher prices. The aggregate supply elasticities over the range of \$1.00/MCF to \$2.00/MCF range from .42 to .47 depending upon assumptions about oil prices. These estimates are higher than those that have been inferred from the November 1974 Project Independence Report. The methodology that produces these figures, and the changes from previous assumptions, are outlined in a later section. A comparison of these estimates and those of other models is also presented.

2.2 Natural Gas Reserves

Additions to reserves are a fundamental element in the forecasting procedure and a popular criteria for evaluating the sustainability of the production estimates. The FEA methodology, expanded below, includes a fixed decline curve which implies a final ration for production and reserves on a regional basis.

In examining natural gas reserves the important numbers are non-associated gas proved reserves at the end of the year and net additions to non-associated gas proved reserves. The relevant historical data for 1966 to 1974 appear in Table 7.

TABLE 7

ANNUAL ESTIMATES OF PROVED NON-ASSOCIATED NATURAL GAS RESERVES IN THE UNITED STATES (TCF)

	Additions to Reserves	Total Reserves at End of Year*
1966	17.0	217.4
1967	17.9	221.8
1968	13.9	220.9
1969	6.8	211.8
1970	9.3	204.1
1971	8.9	195.9
1972	7.8	186.1
1973	3.9	172.2
1974	7.0	162.2

*Includes revisions and extensions.
Source: See Table 1

The regional breakdown of reserves for 1974 end of year are recorded in Table 7.

TABLE 8

ANNUAL ESTIMATES OF 1974 PROVED NON-ASSOCIATED NATURAL GAS RESERVES BY REGION (TCF)

Region	Proved Reserves at End of 1974
Alaska (1)	5.4
Pacific Coast (2)	2.1
Pacific Coast OCS (2A)	0.2
Western Rocky Mtn (3)	9.1
Eastern Rocky Mtn (4)	4.6
W. Texas - E. New Mexico (5)	14.4
W. Gulf Basin (6)	59.8
Gulf of Mexico OCS (6A)	30.9
Mid Continent (7)	30.8
Michigan Basin (8,9)	1.2
Appalachian (10)	3.7
Atlantic Coast (11)	0.0
Atlantic Coast OCS (11A)	0.0
TOTAL	162.2

To obtain production responses, the deregulation of natural gas brings forth reserve additions in 1980 and 1985 at different prices. The sensitivity of these aggregate reserve additions are displayed for 1980 and 1985 as a function of price. Only reserve additions for nonassociated gas are presented, since associated gas is a function of real petroleum prices.

Table 9 indicates the effects of changes in reserve additions as a function of price by region.

Table 9

Non-Associated Gas Reserve Additions (TCF) for 1980 and 1985 by Region (BAU)

	Well-head Price 1975 $	Regions**												
		2	2a	3	4	5	6	6a	7	8,9	10	11	11a	Total
1980	0.60	0.0	0.0	0.0	0.0	0.0	0.0	11.6*	0.0	0.0	0.0	0.0	0.0	11.6
	1.00	0.0	0.0	0.9	4.4	8.9	15.3	28.6	21.2	0.0	0.0	0.0	0.0	79.3
	2.00	0.6	0.0	2.3	6.1	14.0	19.7	28.6	17.2	0.2	1.4	0.0	0.0	70.1
	2.80	0.8	0.0	2.5	6.8	15.3	29.1	28.6	23.1	0.3	1.5	0.0	0.0	108.0
1985	0.60	0.0	0.0	0.0	0.0	0.0	0.0	11.6*	0.0	0.0	0.0	0.0	0.0	11.6
	1.00	0.0	0.0	1.0	4.4	8.9	17.3	51.1	22.6	0.0	0.0	0.0	0.0	105.3
	2.00	1.3	0.5	4.4	11.3	26.2	38.1	51.1	31.5	0.9	2.7	0.0	0.0	168.0
	2.80	2.3	0.9	4.9	13.3	33.8	57.3	51.1	40.5	1.4	3.4	0.0	0.0	208.9

* Drilling in region 6a commences for four years and then ceases.

**For names of regions see Table 8..

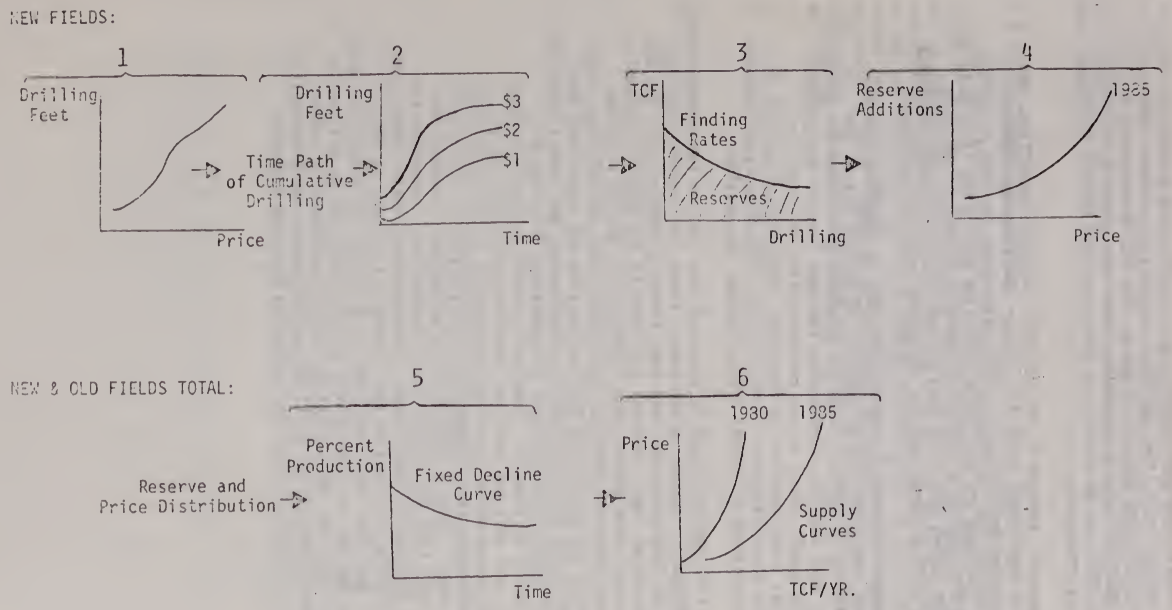
The annual average additions to reserves computed over six years from 1975 through 1980 are comparable to the reserve additions which occurred prior to 1970. In fact, at a $1.00 price, reserve additions average 13.2 TCF per year. Prior to FPC regulations constraining discoveries, the reserve additions including associated gas averaged above twenty TCF per year.

2.3 FEA Forecast Methodology

The estimation of possible natural gas production requires the systematic evaluation of factors such as total available reserves, drilling rates, finding rates, costs of exploration and development, rates of production from established reserves and the interaction of these factors with prices, tax policies, capacity development and leasing policies. The evaluation of particular natural gas policies and the integration of natural gas into the full energy system require an extensive capability to combine these elements and progressively improve the supply assessment.

The schematic of the FEA gas supply model is displayed in figure 2. The full detail of the system, combining associated, non-associated, special regions, and oil prices is not illustrated. In addition, the calculations described occur on a regional basis and actual production and consumption can be affected by demand and transportation differentials when combined in the full Project Independence Evaluation System. However, the general structure and the role of price assumptions are illustrated.

The first stage of the calculations ignores the important time phasing but applies the costing, reserves, and drilling information to estimate the total cumulative drilling that will take place eventually if the price is fixed at a given level. The result, a cumulative supply curve of drilling is input to stage 2. The cumulative supply of drilling at various prices is converted into a time profile of drilling, recognizing the need for gradual adjustment of drilling as increased facilities are developed and equipment is fully utilized over a reasonable life. The time path of cumulative drilling is applied, in stage 3, to a finding rate curve which portrays the total new reserves found as a function of cumulative drilling. This finding rate curve is established by initializing at the current experience, declining the curve exponentially after adjusting to ensure that the cumulative addition to reserves is equal to the U.S. Geological Survey Circular 725 estimate of total reserves. These total reserve estimates vary from the 95% confidence level of 766 TCF to the mean of 961 TCF to the 5% confidence level of 1156 TCF. The pessimistic and optimistic supply projections are taken, in part, from ± one standard deviation according to this distribution.



STRUCTURE OF FEA GAS SUPPLY MODEL

Figure 2

The combination of the drilling time path and finding curves produces, for each year, the approximate supply of reserve additions as a function of price shown in stage 4. For OCS development, the important impact of leasing schedules enters the system by limiting the reserves that can be added in a given year and thereby limiting the resulting production.

Existing reserves, arrayed by the marginal costs of production, are combined with the supply curve for reserve additions and applied to the production decline curve. This determines the rate at which production from reserves will occur over time and is the final step in calculating the supply for different years as a function of price. The FEA model establishes this decline curve to approximate historical rates. The decline curve does not vary with price in this model.

Once the schedule of annual reserve additions is combined with the decline curve, the additions of reserves at various prices are multiplied by the production rates to determine production and price combinations that would be forthcoming for each year of the analysis. The resulting supply curve is the representation of production possibilities, under the list of important assumptions, that can be combined with other estimates of fuel supply, demand and substitution to obtain an estimate of actual production and consumption.

The current FEA model employed is improved over that of the November 1974 Project Independence report in two ways. First, the reserve additions implied by the finding curves have been formally combined with the most recent estimates of total reserves published by the USGS. Previously, the finding rates were established judgmentally and drilling was curtailed when reserves additions approached total availability. This change improves the realism of the finding rate and associated cost estimates for large drilling changes. The second, and more significant change is the internal calculation of cumulative drilling as a function of price in stage 1. Previously, drilling was determined judgmentally and only one drilling curve was available for all prices. This curve was selected to approximate the drilling that would be forthcoming at wellhead prices of $.97/MCF ($.80 in 1973 dollars) in 1985. Table 8 indicates the estimates of production reported at that time and reflects this assumption, an assumption which defers production from higher priced reserves until later years. This simplification was used in the original study because the estimates at that time indicated that these prices and quantities would be sufficient to achieve equilibrium and the focus was on evaluating fuel substitution, not the evaluation supply increments at higher prices. Other improvements in FEA demand estimates have altered the equilibrium price calculations and motivated the more extensive treatment summarized here. It is indicated clearly that higher prices produce significantly higher supplies, and prices higher than today's regulated prices are needed if current consumption levels are to be maintained or forecasted demands are to be met from domestic sources.

2.4 Price Impacts on Demand

The impacts of prices on supply of natural gas are the major focus of this paper, but the corresponding effect on demand should not be overlooked. The revision of FEA estimates for total supply and demand illustrates that regulation can produce major supply deficits or regional imbalances. Due to the known existence of curtailments, an unregulated price may not affect consumption if only unsatisfied demand is being bid away. Conversely, a regulated price would not increase consumption, but would increase the quantity of unsatisfied natural gas demand.

TABLE 10

Original Project Independence Report Supply Estimates[1] (1985)

Price[2]	Non-Associated[3] Gas (TCF)	Associated[4] Gas (TCF)		Total Natural Gas[5] (TCF)	
		$8.48 Crude Price	$13.32 Crude Price	$8.48 Crude Price	$13.32 Crude Price
$0.48	9.48	5.82	6.63	15.30	16.11
0.73	16.66			22.48	23.29
.97	18.14			23.95	24.77
1.21	18.15			23.97	24.78
2.42	18.17			23.99	24.80

[1] Project Independence Report pp. 93 and 94, BAU case.

[2] 1975 prices. In the PIR tables, all prices are given in 1973 dollars.

[3] Southern Alaska and tight gas. The non-responsiveness of supply above $1.20 is due to logistic and institutional constraints.

[4] Quantities of associated gas can be expected to vary with the natural gas price. This variation is not portrayed here. However, this variation with natural gas price is far less than the variation with crude oil price.

[5] This approximation is preliminary since the supply responsiveness with price is biased slightly upward as explained in Footnote 1 and is biased slightly downward as explained in Footnote 3. The overall effect of these offsetting biases, while small, is unclear.

2.5 Comparison of Alternative Supply Forecasts

In this section the FEA model supply forecasts are compared to five other forecasts of long term natural gas supply; the AGA-TERA Model of the American Gas Association, the MIT Model developed by MacAvoy and Pindyck, the SRI-GULF Model developed by Stanford Research Institute, the Federal Power Commission (FPC) and Energy Research and Development Administration (ERDA) natural gas projections. Four of these forecasts are based upon supply response to price (TERA, MIT, SRI-GULF, FPC). The ERDA forecast is a trend projection based upon assumed reserve availabilities.

Table 11

DOMESTIC NATURAL GAS PRODUCTION (TCF)

A Comparison of: FEA, TERA,
MIT, SRI-GULF, FPC, and ERDA
(1980 and 1985)

Year	Price $ '75 ($/MCF)	FEA at Current World Oil Prices	AGA-TERA	MIT	SRI-GULF (Nominal Case)	FPC*	ERDA**
1980	$1.75	20.63	19.6	40.7***	23.3	24.6	22.0
1985	2.00	22.67	21.7	N/A	25.7	26.4	24.5

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* Forecast related to prices of $2.04 and $1.78 for 1980 and 1985 respectively.

** Forecast not related to price.

***The original MIT study limited prices to 90¢/MCF and corresponding production estimates of 32.6 TCF. This 40.7 TCF was attained by solution of the model at the $1.75 price which may be outside the range of reliability.

Strict comparison of the models is difficult due to differences in model construction, techniques, and basic assumptions underlying the forecast. The SRI-GULF Model, as does the FEA Model, solves for equilibrium supply, demand, and prices. The actual equilibrium prices from the SRI Model are $1.73 and $2.07. The TERA and MIT Models do not solve the equilibrium price; the wellhead price is exogenous to each model. The FEA equilibrium prices were input to these models to obtain the supply forecasts. The TERA forecast is about 1 TCF lower than the FEA forecast. In separate analysis, FEA has determined that this model tends to be pessimistic with respect to the drilling success ratios[1/].

[1/] A Comparison of Two Natural Gas Supply Models, by John A Neri, Federal Energy Administration Technical Report 75-15, June 10, 1975, Office of Quantitative Methods, Washington, D. C.

The MIT Model is much higher than all of the presented forecasts. The MIT supply forecasts are very optimistic with respect to discovery size and offshore gas. The SRI Model, while solving for essentially the same equilibrium prices, shows approximately 3 TCF more production than the FEA forecasts for 1980 and 1985. The FPC forecast is taken from the option three case - deregulation of new gas - as presented in "A Preliminary Evaluation of the Cost of Natural Gas Deregulation", January 1975. The forecasts for 1980 and 1985 are approximately 4 TCF above the FEA forecasts. The equilibrium prices from the FPC Model are very different from the FEA and SRI prices. These prices are $2.04/MCF and $1.78/MCF for 1980 and 1985 respectively. This reduction in the supply price is most likely due to the assumed threefold increase in the supply elasticity from .06 to .16 between 1980 and 1986.

The estimates are provided to indicate the range of estimates currently available and the relative position of the FEA forecasts.

Although all the models for which price data are available tend to confirm the FEA estimates about required future equilibrium prices, it is difficult to obtain an exact comparison of price sensitivity of the other systems. For the FEA, TERA, and MIT Models, approximate estimates of the aggregate price sensitivity are displayed in Table 12. As stated above, FEA analysis indicates that the TERA price sensitivity is pessimistic, and that of the MIT Model is optimistic. The FEA estimates, based on the best available data, methodology, and judgments is the most reliable representative of price impacts on supply. This model indicates that 5.3 TCF of additional product can be made available as gas prices increase from $1.00 to $2.00

Table 12

APPROXIMATE 1985 SUPPLY REDUCTIONS DUE TO PRICE CHANGES (TCF)

Wellhead Price (1975 $)	FEA	TERA	MIT **
$2.00	20.8	21.7	40.7
1.00	15.8	18.9	32.6
CHANGE	5.0	2.8	8.1

** These figures are from the 1980 supply estimates for the MIT model with the $2.00 row evaluated at $1.75. Equilibrium solutions to the MIT model occur in 1980 at 90¢/Mcf. 1985 prices in the $2.00 range may be outside of the range of reliability.

3. Estimated Total Costs of Deregulation With S2310 in 1976

While the long-run impacts of natural gas deregulation are important, the short-run effects in 1976 are of interest. Section 4 of this paper examines the impacts of various deregulation proposals on the total fuel bill and the natural gas fuel bill of the residential user in 1985. In this section FEA's estimate of the impact of deregulation in 1976 are presented for the current version of S2310.*

The price of number 2 fuel oil in 1976 is translated into an equivalent retail price for natural gas. A number 2 fuel oil price of $15.50/bbl is comparable to a retail natural gas price of $2.66/MCF. To get the wellhead price, transportation and distribution costs are subtracted. In 1974 the average transportation cost plus distribution mark-up was 55¢/MCF. This yields a deregulated wellhead price of ($2.66 - $.55) = $2.11/MCF.** This estimate is a simplified method for estimating the short-run price change and does not assume any supply response. The deregulated price could be higher or lower if these responses develop.

Given the estimated wellhead prices of $2.11/MCF, the cost increases associated with various categories of natural gas are presented in Table 13.

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* S.2310 is know as the Natural Gas Emergency Act of 1975.

** The $15.50/bbl is the delivered price for oil at the burner tip. The $15.50/bbl distillate oil converts to $2.66/MCF gas. Subtracting the transportation cost and distribution mark-up of 55¢/MCF yields a wellhead price of ($2.66-$.55)= $2.11. This figure is consistent with the PIES estimated deregulation price of $2.13/MCF in 1985. The distillate price of $15.50 is in question, since the December 1975 price of distillate price used to convert to natural gas equivalent prices should be weighted average of both the industrial and residential price. From 1974 data it is derived that the industrial distillate fuel price is 96.4% of the residential price. Therefore using an average 1974 residential distillate fuel price of $15.82/bbl. The approximate industrial price would equal $15.26/bbl. From 1973 data it is found industrial distillate fuel, and the residential sector consumes the remaining 46 percent. Weighting the appropriate residential and industrial prices by these percentages yields an average distillate fuel price of $15.51/bbl. Since the average value of retail distillate is uncertain, a price of $15.50/bbl was chosen.

TABLE 13

FEA ESTIMATES OF 1976 COST INCREMENTS DUE TO DEREGULATION OF NATURAL GAS UNDER S2310

Cost Element	Quantity*	Cost
1) Intrastate Gas	5	4.3
2) Non-Jurisdictional Interstate Sales	1	.86
3) OCS Gas	N/A	0.0
4) Onshore Gas	.3	.26
5) Additional Production	.5	0.0
6) Old Contracts	.3	.04 to .27
TOTAL	7.1	5.46-5.69

To the extent that increased natural gas production replaces higher priced imported oil, the above estimate is reduced.

* The quantities refer only to those increments of gas affected by S2310. Because of long-term contracts or lack of time response some qunatities are not affected (N/A).

4. Long-Term Impacts of Natural Gas Deregulation

FEA estimates of the long-run impact of natural gas deregulation on residential fuel bills are computed for several of the proposed legislative actions pending before Congress. The proposed legislative actions are outlined in an appendix.

This section reports estimates of the anticipated effects of several policy proposals for the field price of natural gas, which is currently regulated by the Federal Power Commission if it is sold for resale across state lines or if it is carried for resale by an interstate pipeline that has been certified by the Federal Power Commission. The results were derived from a parametric framework that uses supply and demand schedule information currently being used as inputs to the Project Independence Evaluation System (PIES). The supply curves are based upon the FEA production model, which uses a discounted cash flow technique to relate production levels with price. The consumer demand relationships are based upon the forecasts for the Federal Energy Administration's Econometric Regional Demand Model (ERDM), in which natural gas was one of several major fuels to be analyzed. This information is used to determine equilibrium prices, production, consumption, and associated economic impacts given certain price constraints on gas under existing interstate contracts and on new offshore gas.

4.1 Methodology

The analysis of the effects of deregulation of natural gas is conducted in the context of the Project Independence Evaluation Systems results for the 1985 $13.00 reference case, which represents the equilibrium solution when new gas is deregulated. For continued regulation, a regulated supply curve is constructed and allowed to equilibrate with a regulated demand curve to produce a new price and production level. A number of simplifying assumptions are made in order to approximate the solution.

The approach assumes a set of separated inter/intrastate markets in which the regulated demand curve is the demand in the region and the regulated supply curve is the supply in the region minus any volume under long-term contract to the interstate market. In the absence of price controls in the inter/intrastate markets, each of these markets will equilibrate

(1) $D_i (P_i) = S_i (P_i) - ECS_i$ for all $i \epsilon I_P$

where D_i is the regional demand, S_i is the regional onshore supply, P_i is the unregulated price, and ECS is the volume supplied to the interstate market under existing contracts.

In addition, nonproducing states satisfy a portion of their demand for interstate gas in 1985 from existing gas contracts

(2) $D_i(\bar{P}) = ECR_i + UD_i (\bar{P})$ for all $i \epsilon I_R$,

where UD_i is the unsatisfied demand in the region and ECR_i is the interstate volume received under existing contracts.

A third class of states produce gas for intrastate use and also receive gas from existing interstate contracts

(3) $D_i\ (P_i,\ \bar{P}) = S_i\ (P_i) + ECR_i + UD_i\ (\bar{P})$ for all $i \epsilon I_{PR}$.

In principle, individual solutions for each state in class I_p can be derived. Further, given data on existing contracts supplied (ECS_i) and existing contracts received (ECR_i) and estimates of unsatisfied interstate demand ($UD(\bar{P})$), equilibrium intrastate prices can be derived for states in class I_p and I_{PR}. Total demand under interstate gas regulation is:

(4) $D^R_{US} = \sum_i D_i$, for all $i \epsilon (I_p \cup I_R \cup I_{PR})$.

An approximation to the above solution can be derived by concentrating on the major producing states (i.e., the WSC demand region) and determining regulated supply and demand for that region.

The following assumptions were made:

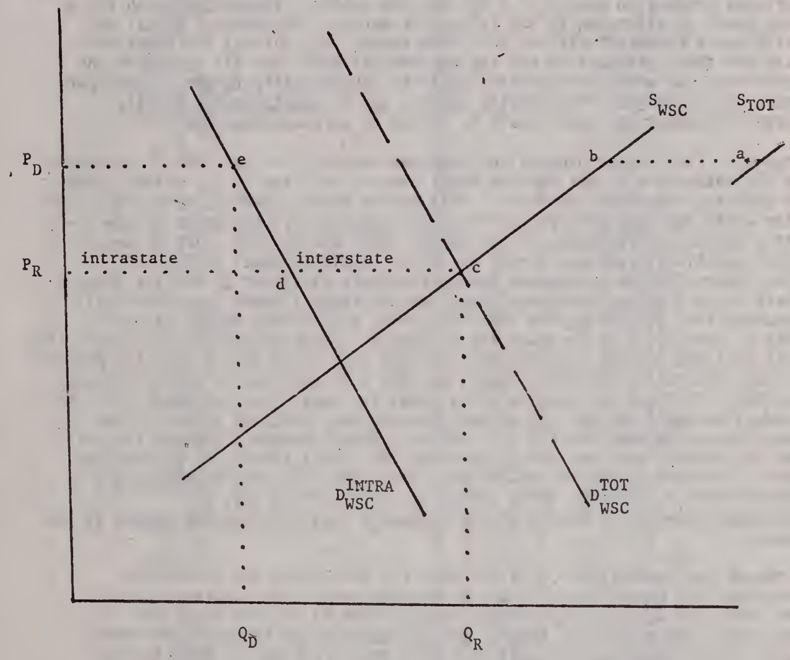
- All West South Central gas consumption is intrastate gas.
- The existing ratio of OCS to non-OCS contracts will be maintained under continued regulation.
- The WSC intrastate market is representative of all domestic intrastate markets.
- Quantities under existing interstate contracts decline at a rate of 7-8% per year.
- The ratio of non-WSC non-Alaskan production to WSC production continues at its present level.
- The intrastate demand curve for WSC is stable under deregulation, i.e., the regulated and deregulated intrastate equilibria are on the same demand curve.

The methodology is summarized in the accompanying graph. With continued regulations, the demand for onshore gas from the West South Central Region is D^{Intra}_{WSC} plus contracted interstate volume, or D^{TOT}_{WSC} which must be satisfied by the available supply, S_{WSC}. The market equilibrates at P_R and Q_R, of which d is intrastate and dc is interstate gas. When new gas is deregulated, interstate consumers bid for this onshore gas as well as for volumes from offshore and Alaska. The new contract price rises to P_d, which expands onshore production in this region to point b, and reduces intrastate consumption along demand curve, D^{Intra}_{WSC}, to point e. In addition, there is increased production in the offshore and Alaskan regions, gas from which must enter the interstate system.

4.2 Estimates of the Impact of Natural Gas Deregulation

Estimates of the effects of continuing present regulations as well as those

FIGURE 3
THE WEST SOUTH CENTRAL INTRASTATE
MARKET UNDER REGULATION AND DEREGULATION



LEGEND:

ab - non WSC supply from PIES
dc - estimated interstate gas under continued regulation
e - deregulated intrastate equilibrium
a - deregulated total natural gas supply
bc - WSC supply expansion due to deregualtion
de - WSC intrastate demand contraction due to higher deregulated price
P_D - deregulated equilibrium price for WSC
P_R _ REGULATED EQUILIBRIUM PRICE FOR WSC intrastate gas

of several recently proposed legislative actions are derived from this methodology and appear in Table 14. The more important results are discussed below.

Present Regulations. With this option only the intrastate market will be in equilibrium. Gas from the onshore areas will be produced until demand in this market is satisfied at a new contract price of about $1.80/MCF. Offshore and Alaskan gas production, on the other hand, is restricted by an assumed FPC field price ceiling of $.60/MCF plus any cost-of-living adjustments. Total marketed production equals 17.9 TCF for the nation, although only 6.6 TCF of this would be allocated to the interstate market. Residential annual gas bills are a comparatively low $215 (the second last column) for those who maintain their gas service but the residential bills for all customers who would have gas under deregulation would be substantially larger at $280 per year, or even higher if synthetic natural gas is substituted. Finally, curtailed industrial users would be forced to purchase imported oil.

Krueger. The Krueger proposal defines new contracts as gas that is dedicated to the interstate market for the first time in addition to any volume under an expiring interstate contract. This option would stimulate more production than would the continued regulation case because: (1) the price of new onshore gas would rise above its $1.80/MCF level and (2) the price of new offshore and Alaskan gas would rise above its regulated level of $.60/MCF. The Krueger offshore provisions are particularly difficult to analyze because there is no a priori knowledge about how the Federal Power Commission will regulate this gas during the 1975-80 period, and current supply estimates make it impossible to forecast the producers' response to a phased deregulation that will end in 1981. The analysis assumes that under both Kruger and Pearson/Bertsen proposals, producers expect in 1976 a deregulated price for OCS gas by 1985. If there are uncertainties about the phasing out of these controls, production would be less and prices greater than indicated in the table. It should be noted that the FEA oil and gas production model, assumes flexible capital markets and does not incorporate any supply effects of an improvement in the gas producers' cash-flow. Thus, when expiring contracts are renegotiated at a market price rather than a regulated one, the improved cash-flow situation of the producers does not increase supply in the model.

Although gas expenditures will increase (as both price and production increase) oil expenditures in the interstate region will decrease. The net effect on total energy expenditures (column 4) is very small and therefore, the effects of natural gas deregulation on the costs of other goods and services (as a result of higher energy prices) is anticipated to be minimal - about $1 per person by 1985. Studies that relate increased gas costs to the general price level of the nation's goods and services are erroneous because they fail to account for the important substitution of gas for oil when natural gas is deregulated. In the interstate residential market, annual gas bills would increase to $304 to a group of consumers who would be paying $280 for both gas and oil under the continuance of the present regulations.

Pearson-Bentsen. The two main differences between this and the Krueger option are that: (1) gas under expiring contracts would continue to be regulated (at the assumed FPC ceiling of $.60/MCF plus any cost-of-living adjustments)

Table 14

1985: Comparison of the Effects of Proposed Natural Gas Legislation
(All Prices are in Constant 1975 Dollars)

	Nation				Interstate				
Policy	Marketed Gross (Tcf)	Production Net a/ (Tcf)	Average Field Price b/ ($/Mcf)	Net Energy Expenditures c/ Per Capita ($/Yr)	Sales (Tcf)	Industrial Price ($/Mcf)	Residential Price ($/Mcf)	Residential Annual Gas Bill d/ ($/Yr)	Residential Annual Fuel Bill e/ ($/Yr)
1974	21.6	18.8	.30	-	11.6	.68	1.47	170	170
Present Regulations	17.9	15.9	1.24	160	6.6	1.08	1.85	215	280
Krueger	22.3	20.0	1.71	161	12.1	1.85	2.62	304	304
Pearson-Bentsen (Passed)	23.0	20.7	1.72	166	13.2	2.70	1.77	205	205
$1 National Ceiling Price	15.8	13.9	.80	130	9.1	1.20	1.97	229	260

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a/ Gas consumed by end-users from domestic sources, excluding liquified natural gas, synthetic fuels and imported natural gas.

b/ Total gas revenues per mcf of net marketed production.

c/ Sum of revenues for gas and for required oil imports to satisfy the demand under deregulation, divided by a projected population of 244 million in 1985.

d/ Assumes that residential customer uses the same gas volume (116 mcf) as he did in 1974, even at higher prices.

e/ Represents the residential bill if the consumer replaces the gas available under deregulation with distillate oil, (using the residential price when crude oil is imported at $13/BBL). This calculation assumes that by 1985 residential users will be curtailed in proportion to their present share of the interstate market. Although curtailments in the past have predominately affected industrial users, many of the seriously curtailed pipelines have already lost much of their industrial load, leaving the residential customer served by these pipelines vulnerable. If interstate customers replace natural gas with synthetic fuels, the fuel bill under regulation and under the national ceiling price will be greater than that indicated above.

(2) the cheaper old gas would be allocated first to residential users. Both of these provisions place greater pressure on the bidding for new gas, causing the new contract price to be greater than in the Krueger option.

The provision that extends the regulated price to expiring contracts reduces the supply of gas that can be sold at the unregulated price. Paying an average price for all gas, consumers would bid the new contract prices higher than if a smaller volume of old gas was to be price-controlled.

The allocation of cheap gas to residential users does not encourage homeowners to conserve gas as much as they would under the Krueger option and, consequently, this reduces the volume that would be available to industries. To allocate this smaller supply of industrial gas among competing users, higher new contract prices would be negotiated, thereby eliminating industrial uses for which the value of gas is not equal to or above this higher price. As a result, the industrial price would be considerably larger than with the Krueger proposal, and this increase would be passed through to households when they purchase other products and services. Thus, the higher new gas and industrial prices would mean that all consumers who buy products and services would be asked to subsidize the homeowner who burns natural gas. (In addition, it is not clear that these price provisions will actually protect the residential customer from higher costs. A lower industrial load is likely to make it more costly for utilities to meet the highly seasonal demand for residential customers. The gas and fuel bills in the table do not account for any such increases in the residential distribution costs.

The higher new gas prices would stimulate some additional production above that in the Krueger option.[1] Although interstate residential prices are lower, interstate industrial and intrastate prices are substantially larger, resulting in a small increase in average field price. Net energy expenditures per capita (column 4) is increased as a result of greater gas production (there are not additional oil expenditures as a result of excess demand in either case because natural gas demand is satisfied with either option). From an economic efficiency perspective, the additional domestic production of natural gas, which is made necessary by the greater subsidized residential demand, would not be warranted because domestic resources could be more productive if they were engaged elsewhere in the economy.

1/ The conclusion about greater production may not appear obvious from the discussion in the preceding paragraph because interstate residential consumption is increasing while interstate industrial and intrastate consumption is declining as compared to the results of the Krueger option. Increased production can be shown, however, by initially noting that in the Krueger case, total gas production is 22.3 TCF when the new contract prices reaches $2.10 per MCF. The Pearson-Bentsen pricing provision would augment this consumption level at that price by an amount equal to the difference between residential consumption at the lower Pearson-Bentsen price and that at the higher Krueger price. In short, subsidizing residential users increases the Bentsen residential level, resulting in higher new contract prices and more production.

TABLE 15

PROJECTED INTERSTATE/INTRASTATE SALES UNDER DIFFERENT POLICIES, 1985

	Marketed Production		Sales	
Policy	Gross	Net*	Interstate*	Intrastate*
1974 Data	21.6	18.8	11.6	7.2
Present Regulations	17.9	15.9	6.6	9.3
Krueger	22.3	20.0	12.1	7.9
Pearson-Bentsen	23.0	20.7	13.2	7.5
$1 National Ceiling	15.8	13.9	9.1	4.8

* Gas consumed by end-users from domestic sources, excluding liquified natural gas, synthetic fuels and imported natural gas. Total gas consumption (including these other sources) would be greater.

$1 National Ceiling Price. There have been some proposals to extend price controls to the intrastate market. In Table 14 the results of a one dollar ceiling for all new gas are presented. This option would provide for some increments from offshore and Alaskan fields but would roll back substantially the equilibrium intrastate price under the continued regulated case (by 1985, from $1.80/MCF to $1/MCF). Total gas production would decline to 15.8 TCF with excess demand being created in both the intrastate and interstate markets.

4.3 The Interstate-Intrastate Distribution of Natural Gas Supply

The differences between deregulation and regulation are substantially more pronounced for interstate supply than for total national production. With the continuation of the present regulations at today's prices (in constant dollars), interstate supply would decline about 5.0 Tcf below its 1974 level of 11.6 Tcf - a reduction of 43 percent. If new gas is deregulated (as in the Krueger proposal), the higher gas prices would allow large volumes of gas to enter the interstate market, because not only will more offshore and Alaskan gas be produced but also some onshore gas will be bid away from the intrastate market. Under these conditions, the decline in interstate sales would be halted, resulting in slightly more sales than its present level by 1985. The Pearson-Bentsen proposal would increase interstate sales mainly through bidding gas from the intrastate market. It does this, however, at the expense of higher new gas prices and significantly higher industrial prices.

Statement of Leonard Ross, Public Utilities
Commissioner, State of California

Thank you very much for the opportunity to appear before the Subcommittee. The statement I am making is my own rather than the California Commission's, but on several of the issues the Commission has taken formal action which I will indicate.

The California Commission voted unanimously last August to oppose deregulation of natural gas. This action represents a reversal in the Commission position, and specifically a change of opinion by three of the Commissioners appointed before 1975. The reason for this change was the Commission's experience in relation to natural gas from the Prudhoe Bay field in Alaska.

Prudhoe Bay is the largest uncommitted gas reserve in the United States. Proven reserves amount to 26 trillion cubic feet -- the equivalent of thirteen years' consumption in California. Possible reserves may amount to several times this amount.

Three oil companies -- ARCO, Exxon and BP-Sohio -- control 96% of the Prudhoe Bay reserve (excluding the State of Alaska's royalty share). All three companies signed agreements with interstate pipelines in which "negotiating rights" for the gas were committed in return for advance payments. Two of the producers, ARCO and Exxon, signed similar agreements with California gas distribution utilities (Southern California Gas Co. and Pacific Gas and Electric Co., respectively). These agreements were subject to the jurisdiction of the California Public Utilities Commission, which accounts for our involvement.

We approved those agreements, under protest, because we were told that the gas would be committed to interstate pipelines outside of California if we did not match terms which were essentially similar to those available to the producers under the Federal Power Commission's Order No. 499. At the same time, we urged the FPC to abolish its advance payments program, especially with respect to the Alaska gas. On December 31, the FPC took that action.

My concern over the deregulation of the Alaska gas is two-fold. First, it seems likely that the demand for advance payments would once again be made, and met, under deregulation. Advance payments for Alaska gas would cost consumers in 33 states over $1.5 billion, based on the agreements signed prior to the FPC's December 31st order. California's share would be $608 million; Michigan's share would be $139 million;and Ohio's share would be $135.6 million. I question whether these sums represent anything other than a monopoly exaction. As the FPC found, there is no evidence that ARCO and Exxon, at least, could not raise capital on the credit markets. Compulsory finance of large oil producers by natural gas consumers seems to me to have no legitimate justification.

In addition to advance payments, the agreements signed by the Prudhoe Bay producers provided outlines for the gas purchase contracts to be signed at a later date. These outlines include pricing provisions which would take effect if Congress votes deregulation. The pricing clauses are essentially similar among the three producers, and provide that the price shall be the highest of three prices: (a) a minimum price to be negotiated; (b) "commodity value" less treatment and transportation costs; (c) any higher price obtained by any Prudhoe Bay seller in any long-term contract for substantial gas deliveries to the lower 48 states.

This last clause -- the "most favored nation" clause -- is an index of how the market power of the gas producers in Alaska would be used under deregulation. It would expose all buyers to the price paid by the most desparate buyer to the strongest seller in any single transaction. It would set price, not at a bargaining table, but in an echo chamber.

"Most favored nation" pricing may have some justification in the context of a competitive market. But as used in Alaska, it simply compounds the market power of the three producers. At the request of the California PUC, State Attorney Generaly Evelle J. Younger has provided a preliminary opinion stating that there is a "strong probability" of violations of federal antitrust laws in the "most favored nation" clause and other aspects of the Alaska funding agreement.

The case for deregulation is premised on the assumption that there is a competitive market among natural gas producers. I have some question as to the accuracy and relevance of that assumption outside of Alaska, and I would urge Congress not to enact any measure of deregulation even outside of Alaska if it does not have the strongest provisions for recapturing excess profits and dissolving monopoly power. In the case of the Prudhoe Bay field, there can be no question of the existence and costly effect of monopoly power. Utilities and pipelines are desperate for natural gas and will pay virtually any price to obtain a commitment of the Prudhoe Bay reserve. Deregulation, in this context, is simply turning over control from five Federal Power Commissioners to three oil companies. Continued regulation of the Prudhoe Bay reserve is, in my view, the only practical remedy against monopoly pricing.

The other issue I would like to address concerns air pollution problems. Conversion of electric utility boilers from gas to fuel oil is expected to increase smog in the Los Angeles air basin by over 30% in the next few years. Other areas of the country will also experience, or have already experienced, great deterioration in air quality. This is not to argue that gas should continue to be burned in boilers year-round; obviously, we don't have enough. But any statutory prohibition of boiler fuel use of gas should contain broad and flexible authority to meet seasonal or emergency air pollution problems. This authority should not be limited to pollutants for which federal standards have been set -- some of the most severe problems arise from acid aerosols, nitrates, and sulfates, for which no federal standards are likely for several years. In areas such as Southern California, a combination of high sulfate levels and high oxidant levels creates critical health problems. In Baltimore, the worst combination is likely to be high sulfate levels, high humidity and low temperature. In Pittsburgh, the problem arises from a combination of high sulfur dioxide and high particulate levels. To meet these varying problems in a timely and discriminating manner, authority to make exceptions for air pollution reasons should be vested in the Environmental Protection Agency.

COST TO CONSUMERS OF ALASKAN ADVANCE PAYMENTS
(Estimated from the Agreements Concluded
prior to December 31, 1975)

Alabama	$600 thousand	Nebraska	$42.2 million
Arkansas	$200 thousand	Nevada	$1.6 million
California	$608 million	New Jersey	$29.1 million
Colorado	$100 thousand	New Mexico	$3 million
Idaho	$2.4 million	New York	$11.1 million
Illinois	$48.1 million	Ohio	$135.6 million
Indiana	$38.1 million	Oklahoma	$9.3 million
Iowa	$75.3 million	Oregon	$5.3 million
Kansas	$12.0 million	Pennsylvania	$76.8 million
Kentucky	$7.6 million	South Dakota	$7.5 million
Louisiana	$7.5 million	Tennessee	$0.6 million
Maryland	$24.7 million	Texas	$6.0 million
Michigan	$138.8 million	Virginia	$13.9 million
Minnesota	$108.5 million	Washington	$8.1 million
Mississippi	$7.6 million	West Virginia	$11.9 million
Missouri	$1.5 million	Wisconsin	$96.1 million
Wyoming	$4.0 million		

STATEMENT OF
DAVID C. SWEET
COMMISSIONER
PUBLIC UTILITIES COMMISSION OF OHIO
BEFORE THE SUBCOMMITTEE ON ENERGY AND POWER
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
U. S. HOUSE OF REPRESENTATIVES

Friday, January 23, 1976

SUMMARY

Recent emergency purchases of high-priced natural gas by Ohio gas utilities to relieve industrial and commercial curtailments has given the State of Ohio a preview of the impact and consumer response to permanent natural gas deregulation. It is estimated that Ohio gas consumers would pay up to $868.8 million more each year if deregulation legislation is enacted by the U. S. Congress.

Based on the Ohio experience with "mini-degregulation," the U. S. Congress should resist pressure to act on deregulation until the facts on natural gas supply and reserves are developed from sources independent of the gas industry.

Mr. Chairman and Members of the Subcommittee:

I appreciate the opportunity to testify today on what may be the most important utility regulation issue of this decade: the question of natural gas deregulation and the broader impact of that policy on the way natural gas is purchased, allocated, curtailed and priced.

I serve as a Public Utilities Commissioner in Ohio -- the state hardest hit by recent shortages and resulting curtailments of natural gas. Ohio industry depends heavily on natural gas, consuming 40 percent of all gas used in Ohio each year. And Ohio is heavily dependent on interstate supply -- 93 percent of Ohio's natural gas comes through interstate pipelines.

Last fall, major gas distribution companies in Ohio faced curtailments up to 28 percent from their pipeline suppliers. Columbia Gas of Ohio, which supplies 48 percent of all major gas utility industrial customer requirements in Ohio, expected to be able to meet only 34 percent of industrial requirements in its service area. Columbia, in fact, predicted thousands of layoffs as a result of heavy curtailments to industrial customers in Ohio this winter.

To date, the relatively mild winter, the national economic recession and multiple emergency purchases of natural gas from the Southwest United States have eliminated the prospect of heavy job layoffs in Ohio. But the Ohio Public Utilities Commission has been forced to take serious steps to curtail and allocate the use of natural gas by Ohio consumers. In Public Utilities Commission curtailment orders beginning in 1972, we have prohibited any new service connections for all Ohio residential, commercial and industrial consumers in Ohio. Not a single new home built in Ohio can be heated with natural gas. Not a single new or expanded industry can qualify for new gas hook-up. As state development director from 1971 to 1975, I witnessed firsthand what that reality does to an aggressive state economic development program. The Commission has approved end-use curtailment plans calling for 100 percent curtailment of natural gas used for boiler fuel and electric power generation.

As an Ohio Public Utilities Commissioner, therefore, I am vitally interested in any policy or program at the federal level that would relieve the natural gas supply shortage Ohio is currently experiencing and will continue to experience in coming years. As a Public Utilities Commissioner, I believe Ohio gas utilities and their suppliers should receive compensation which would cover all prudent costs and provide a fair rate of return on investments. But, as a Public Utilities Commissioner, I want to make sure Ohio consumers are protected from manipulation of the facts by the gas industry to gain approval of deregulation legislation before the United States Congress. I want to make sure consumers -- and their elected representatives -- have the opportunity to test the claims made in the current unprecedented barrage of pro-deregulation gas industry advertising against straight, independent facts. Ohio congressmen certainly will have to defend their votes on the deregulation issue. want to make sure Ohio consumers know what natural gas deregulation, a proposed by S.2310, Title II, will cost them in the coming years, and what that price tag will really buy in terms of increased supplies to Ohio industry. I would like to take this opportunity to commend Senator John Glenn (D-Ohio) for his initiative in proposing Title I -- an emergency action which would meet Ohio's immediate need for additional natural gas supplies, while providing the time needed to develop natural gas supply data independent of the gas industry.

Each of these questions has been brought into sharp focus in Ohio in the last three months by emergency purchases by Ohio gas utilities of short-term, high-priced gas from the Southwest United States. We have had a unique opportunity in Ohio to experience a preview of the impact of permanent natural gas deregulation. And I want to describe for the members of this subcommittee Ohio's response to this "mini-deregulation" -- because I believe that response is truly a forecast of things to come.

I think it is important to examine Ohio's experience with deregulation within the context of a broader issue -- the issue of consumer credibility with respect to energy policy. I would suggest to you that in Ohio the credibility of the energy industry, and state and federal government on energy policy, regulation, supplies and prices is virtually non-existent. The Ohio consumer has been abruptly shaken out of the fantasy world of Reddi-Kilowatt. The promises of unlimited, cheap, clean energy have become the reality of skyrocketing electric bills, cold schoolrooms and industrial layoffs due to gas curtailments. Ohio consumers simply do not now believe what they're told about energy supplies or prices -- they don't believe the energy industry and they don't believe government officials.

The Ohio Public Utilities Commission has asked the Federal Power Commission to independently develop the facts on natural gas supply and reserves. On February 20, 1975, the Ohio Public Utilities Commission, joined by 15 other states, asked the Federal Power Commission to convene a joint board of state regulatory agencies to investigate the natural gas supply situation. We informed the Federal Power Commission that we could not make responsible regulatory policy in Ohio without independent facts on gas supply. Our request was denied by the Federal Power Commission on September 16. They said a joint board would be "unwieldy, procedurally inefficient and therefore inexpedient to the public interest." On October 16, the Ohio Public Utilities Commission filed for rehearing with the Federal Power Commission. That action was also denied. The Ohio Public Utilities Commission has petitioned the United States Court of Appeals to reverse these Federal Power Commission decisions. Why has the Federal Power Commission consistently refused to undertake an independent investigation of the natural gas supply situation with state regulatory commissions? Why has the Federal Power Commission already determined its position on the question of natural gas deregulation without independent facts? In a full page ad currently running in Ohio newspapers, Columbia Gas says, "We agree with the Federal Power Commission that 'deregulation of new natural gas at the wellhead is the single, most effective measure that can be taken to alleviate the nation's severe supply-demand imbalance'." (See attachment)

The Ohio Public Utilities Commission has also intervened in hearings before the Federal Power Commission into allegations that major gas producers failed to fully explore and develop natural gas reserves in the Gulf Coast region.

The absence of independent data on natural gas supplies has damaged the credibility of the energy industry and government. And the performance of the oil and gas industry relative to price and supply has further eroded credibility with consumers.

Two years ago, consumers were told they would have to cut back their consumption of gasoline because of the Arab oil boycott. They waited in line at gas pumps for months. Now we are told there is a surplus of gasoline -- and higher prices.

This fall, Ohio gas utilities, as well as the federal government, forecast a bleak winter for Ohio and other industrial states. Ohioans braced for heavy gas curtailments for industry and massive job layoffs. Ohio's largest supplier -- Columbia Gas -- informed its industrial customers in July and August that they should anticipate 100 percent curtailments of large industrial boiler loads and 65 percent curtailment of remaining industrial loads beginning in November. Testimony at public hearings before the Public Utilities Commission in September, 1975, on Columbia's winter curtailment plan indicated 65 percent industrial curtailment would result in as many as 100,000 Ohioans out of work. At no time during those hearings did Columbia suggest any source of additional gas supplies this winter.

On September 17, at the invitation of Representative Wayne Hayes, the Ohio Congressional Delegation met with representatives of Ohio natural gas utilities, the Public Utilities Commission of Ohio, the Federal Power Commission and others. The purpose of the meeting as stated in the telegram inviting participation of the of the Public Utilities Commission of Ohio was: ". . . to discuss availability to Ohio of intra state gas supplies from other gas producing states." Senator John Glenn's emergency natural gas bill was a major subject of the meeting. At no time during the meeting was the possibility of emergency gas purchases under FPC Rule 2.68 discussed by representatives of Columbia or the FPC as a means of meeting the pending Ohio emergency.

In the first 21 days after the Public Utilities Commission issued its curtailment order, Columbia increased its gas supply by more than 22 billion cubic feet, including a single emergency purchase of 13.1 billion cubic feet from the Southwest. The cost of emergency purchase gas is averaging $2.57 per mcf -- more than twice the cost of regulated interstate gas ($1.20 per mcf). Columbia also announced a change in corporate gas storage policy would release additional supplies for use in Ohio this winter.

Columbia's sudden acquisition of new supplies enabled the company to reduce curtailments by as much as 80 percent in some industrial categories. All additional supplies were intended for distribution only to curtailed industrial and commercial customers.

Last month, Columbia announced its intention to "roll-in" the cost of these emergency gas purchases to all consumers through their Purchase Gas Adjustment Clause. That means Columbia is asking residential customers to help pay for emergency purchase gas at a cost of $33.7 million that will be used only to relieve industrial and commercial curtailments. Residential consumers are faced with the prospect of paying more for gas they will not use.

Public opposition to this announced plan has been loud, intense, and prolonged. Public opposition to charging residential consumers for emergency purchase gas includes Ohio's Attorney General, Ohio's State Auditor, major Ohio consumer groups, and members of Ohio's Congressional delegation. A state representative and 18 co-sponsors have introduced a bill into the Ohio General Assembly to block "roll-in" of emergency purchase "deregulated" gas costs to residential consumers.

I would like to pose to this subcommittee the questions I am asked by Ohio consumers: Is the natural gas industry withholding gas supplies until an opportunity to charge a higher price is provided by the federal government? Is the natural gas industry manipulating gas supply data to pressure the United States Congress into deregulation?

Columbia Gas is spending thousands of dollars in advertising to answer those questions for Ohio consumers. Columbia's current ad states: "Do not be lulled into a false sense of security. The natural gas shortage is very real. Columbia is working hard to get additional supplies of gas because we know there is simply not enough gas currently available to meet all customer needs." The ad continues, "The hard fact is the natural gas shortage can only get worse unless Congress acts now (to deregulate)." Are these the "hard" facts?

I believe Ohio consumers simply will not accept deregulation or any major change in gas regulation policy until they are given straight facts from a source independent of the major gas companies. Ohio's recent experience with Columbia's emergency purchase of high-priced gas has made the credibility problem even more severe and the need for independent data even more important.

Columbia's purchase of higher-priced emergency gas also provides a forecast of what natural gas will cost if deregulation legislation is enacted.

A study by the Library of Congress' Congressional Research Service, titled "The Economic Impact of S.2310's Pricing Provisions," predicts that industrial users of natural gas will, under deregulation drive gas prices up to or beyond the level of light oil and propane -- the closest substitute for natural gas. The study says propane currently sells for about 23¢ per gallon or $2.50 per million BTU or Mcf equivalent, while #2 fuel oil sells for $15.50 bbl or $2.50 per Mcf equivalent. The study, therefore, projects natural gas prices under deregulation to rise to at least $2.50 per Mcf. (well head price

(In Ohio, propane currently sells for $4.80 per Mcf equivalent and #2 fuel oil sells for about $2.73. The average cost of Columbia's emergency purchase gas in Ohio has been $2.57 per Mcf.)

Based on that assumption, the Library of Congress study predicts gas consumers in the United States will pay $20.3 billion to $30.8 billion extra each year by 1980 if S.2310 is enacted. Ohio's share of that increase after deregulation will be up to $868.8 million in higher gas bills each year -- a 37 percent increase over what Ohio gas consumers currently pay for natural gas. (See attachment)

David S. Schwartz, formerly assistant chief of the Federal Power Commission's Office of Economics in a January 21, 1975 speech, offered another reason for the predicted rise in natural gas prices under deregulation to or beyond the level of competing fuels: the concentration and lack of competition within the energy industry. He states that of the 18 major petroleum companies, all are in natural gas, 16 are in oil shale, 10 are in coal and 16 are in uranium Schwartz suggests that this kind of concentration provides no incentives for price competition among fuels.

Russell J. Profozich, National Association of Regulatory Utility Commissioners Assistant Director of Economics, in a report titled "Current Issues of Natural Gas Supply," also suggests that the competitive nature of the natural gas industry is critical to the impact of deregulation on gas price levels. He states,

> "If an industry is not competitive; that is, if the dominant firms within an industry have sufficient market power to affect the terms at which their product is sold; then an unregulated price will reflect the dominant position of the firms within the industry. The established price, then, is likely to be above the competitive price (arrived at in a freely competitive market) and consumers will pay higher prices as a result."

I do not come before this subcommittee as a strong proponent of regulation. But I am faced with three alternative regulators of the future price of natural gas: the O.P.E.C. nations, the gas industry or the Federal Power Commission. Given those alternatives, I would favor continued Federal Power Commission gas price regulation.

Columbia's newspaper ad states, "The quickest, surest, the most effective way to increase the vital supply of natural gas is to end the present outmoded system of government control over the price producers are allowed to charge for their gas." The ad continues, " . . . the choice is between paying more for less gas . . . or paying more for more gas."

Will the $20 to $30 billion increase in consumer gas bills buy a substantial increase in gas supplies? Profozich cites statements by proponents of continued gas regulation that proven reserves of natural gas are likely to continue to decline, though perhaps at a slower rate, no matter what the price is. The real problem is that the "recent price increase granted by the Federal Power Commission and the proposals for deregulation initiated by the federal government have caused the natural gas producers to withhold gas from the interstate market in anticipation of higher prices once regulation is removed."

From 1972 to 1974, the Federal Power Commission raised interstate natural gas prices by more than 200 percent (20¢ to 50-55¢ per Mcf). In 1972, new additions to gas supplies totaled 9.6 trillion cubic feet. In 1973 new supply additions *dropped* to 6.5 trillion cubic feet.

In testimony before this committee, Assistant Comptroller General Phillip S. Hughes stated that with continued low prices, "natural gas supplies should decline about 20 percent by 1985. Even with deregulation, natural gas supplies are likely to continue to decline although more slowly -- about 13 percent by 1985." The possibility exists that under a policy of deregulation, consumers could in fact pay more for less gas.

In conclusion, the consumers of Ohio are now demanding straight answers from the energy industry and government on the current and future supply of natural gas. In the absence of a free market situatio they are demanding tight, responsible regulation of a monopolistic energy industry. Given the Ohio experience with and reaction to "deregulated" emergency gas purchases this winter and their anticipated costs to consumers, I believe Ohio consumers will not consider or accept permanent deregulation *until* and *unless* these demands are met.

Pollster Louis Harris says that most Americans (71%) complain in loud and clear terms that "the trouble with most leaders is they treat the public as though it has a 12-year-old mentality, instead of as grown-up human beings who can take the *hard truth* on most issues." And by an even larger majority (85%), Americans feel that "most government leaders are *afraid to tell it like it is* -- to tell the public the hard truth."

I would urge the members of Congress to resist mounting pressure to act on deregulation without the facts, and I hope members of Congress have the courage to discover the hard truth about natural gas supplies and tell it like it is to American consumers.

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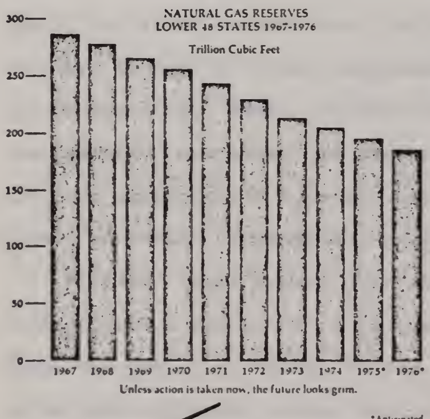
This concludes my statement, I would be happy to answer questions.

Some people believe the natural gas shortage is over. Because that's what they want to believe.

The hard fact is—the natural gas shortage can only get worse unless Congress acts NOW.

① Delusions of adequacy. Thus far, the heating season has been warmer than usual. This, plus a general slowdown in industry, has eased the demand for natural gas — temporarily. Do not be lulled into a false sense of security. The natural gas shortage is very real. Columbia is working hard to get additional supplies of gas because we know there simply is not enough gas currently available to meet all customer needs. We cannot afford to be complacent over a temporary easing of the problem. This chart, showing the declining gas reserves in the lower 48 states, demonstrates America's gas supply crisis:



Unless action is taken now, the future looks grim.

*Anticipated

② You're paying for the shortage. Industries that cannot get enough gas are forced to use more expensive fuels. These higher costs are passed along to you in the form of higher prices for their products. Some companies simply cannot afford the high costs of alternative fuels. In those cases, the price could be more than money . . . it could be jobs.

A new homeowner who can't get gas service must pay almost twice as much to heat with oil; four times as much to heat with electricity.

③ How will your Congressman vote? The quickest, the surest, the most effective way to increase the vital supply of natural gas is to end the present outmoded system of government control over the price producers are allowed to charge for their new gas. This outmoded system simply doesn't work. It discourages drilling when drilling should be encouraged. This outmoded system has created the natural gas shortage despite all our efforts.

Example: The current ceiling price on new gas is 52¢ a thousand cubic feet (Mcf). Columbia knows from its own experience drilling in the Gulf of Mexico that the cost of finding and developing new gas is at least $1.50/Mcf. Would you spend $1.50 for something you could sell for only 52¢?

This month the House of Representatives will vote on a proposal to end federal controls on the price of new gas. The Senate has already passed this much-needed bill.

④ What are the choices? A government energy official recently summed up the gas supply and cost problems when he said, the choice is between paying more for less gas . . . or paying more for more gas. Unfortunately, the one thing the government can't seem to control is inflation. It continues to push up all costs, and these higher costs will be reflected in higher gas bills . . . decontrol or no decontrol.

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We agree with the Federal Power Commission that "deregulation of new natural gas at the wellhead is the single, most effective measure that can be taken to alleviate the nation's severe supply-demand imbalance."

If you agree, let your Congressman know of your concern. Time is running out.

COLUMBIA GAS

CG-363

ESTIMATED IMPACT ON OHIO OF NATURAL GAS DEREGULATION
BASED ON: "ECONOMIC IMPACT OF S.2310'S PRICING PROVISIONS"
LIBRARY OF CONGRESS - CONGRESSIONAL RESEARCH SERVICE
December 31, 1975 (Lawrence Kumins)

SUMMARY OF INCREASED COSTS (p. 12)

Nonjurisdictional Interstate sales	$1.3 Billion
Outer Continental Shelf Gas	1.9
Onshore Gas	1.3
Additional Reserves (3TCF)	7.5
Old Interstate Gas	1.9
Contract Leakage	2.1
Total*	$16.0

*Excludes Intrastate increase of $6.3 Billion because it has little applicability to Ohio.

OHIO SHARE OF NATURAL GAS CONSUMPTION

1974 Ohio Natural Gas Consumption	1.074 T.C.F.
1974 U. S. Natural Gas Consumption	19.761 T.C.F.
Ohio as a % of U. S.	5.43%

PRESENT COST OF 1974 CONSUMPTION

1.074 T.C.F. X $1.40 MCF = $1.503 Billion

OHIO'S SHARE OF INCREASED COST ATTRIBUTABLE TO DEREGULATION

5.43% X $16.0 Billion .869 Billion

TOTAL COST TO OHIO	$2.372 Billion
PERCENT INCREASE IN COST	37%

HEARING
BEFORE THE HOUSE COMMERCE COMMITTEE
The Honorable John Dingell
Room 2122, Rayburn House Office Bldg.
3:00 p.m. - January 23, 1976

Testimony of:

Commissioner Ralph H. Wickberg
Idaho Public Utilities Commission
Statehouse
Boise, Idaho 83720
(208) 225-7095

MR. CHAIRMAN:

My name is Ralph H. Wickberg, a Commissioner for the last seventeen years on the Idaho Public Utilities Commission. I am the Immediate Past-President of the National Association of Regulatory Utility Commissioners, NARUC. I am appearing here today before your committee to present my own personal views on de-regulation of natural gas and also to give a few comments on the proposed bills that your committee is considering.

Some of the material I am going to present to you will be orientated toward the Pacific Northwest and its gas supply - and a few comments alluding to the problems we face in the Northwest may give you a clearer idea as to the views that I may present on natural gas de-regulation.

First of all, I want to make sure that my testimony in favor of natural gas de-regulation only applies to new natural gas supplies and not to present flowing gas. The Federal Power Commission has ample authority to rule in specific cases that deal with pricing problems on existing, flowing gas contracts. Washington, Oregon, and Idaho are served by the Northwest Pipeline Company - and the Northwest Pipeline Company is the sole supplier of natural gas to this region. Two-thirds of the natural gas consumed in the Northwest comes from British Columbia and Alberta. The price at the U.S. - Canadian border up until November of 1973 was 32¢ per 1000 cubic feet. This was probably too low a price for the U.S. to pay to Canada. However, in the past twenty-seven months, the price has escalated from 32¢ per 1000 cubic feet at the border to the present $1.60 at the border. This increase in price has not resulted in additional gas supply - on the contrary - the supply of natural gas from Canada over that same period of time has diminished. The prognosis for increased supplies from our neighboring country is not too bright.

The present well-head price authorized by the Federal Power Commission within the United States is about 52¢ per 1000 cubic feet and the Pacific Northwest, like other areas of the country, is not receiving additional supplies of gas at that well-head price. I, like everyone else, am opposed to paying higher prices for any commodity unless absolutely necessary. It is my opinion that higher well-head prices within the U.S. would result in additional supplies. I also believe that additional domestic supplies are absolutely essential to avoid the possibility of future curtailments of natural gas from Canadian sources. I do not have any absolute proof that any given level of higher price for natural gas at the well-head would result in significantly higher quantities of natural gas supply, but from my personal knowledge and experience, I believe the supplies would increase.

Another item I would like to call to your attention which I believe is different in the Pacific Northwest than in some of the other areas of the United States is that most new homes in southern Idaho and also in northern Idaho and parts of Washington are going "all electric." A large part of the reason for the high incidence of new homes to electric heat is the fear of a short supply of natural gas. People hesitate to make an investment in natural gas heating facilities that would normally last twenty years if they are not convinced that the gas suuply will be ample for that entire period. For example, 80 to 90 percent of new homeowners are choosing electric heat in portions of the Pacific Northwest. This, along with converting existing homes to all-electric, plus new commercial and industrial uses, is placing great demands for future additions to electric generation. What I am attempting to say is the existing investment has already been made in natural gas facilities and if uncertainties of supplies were removed, a more normal relationship would exist between these two fuel sources. New electric generation causes serious economic inpacts to existing customers because of the higher costs of the new facilities. Part of the requirements for new generation would be unnecessary if an assured supply of natural gas were available.

I believe the long-range public interests would be served by any intelligent effort to improve natural gas supplies - not only for residences and commercial uses - but also for certain industrial uses for which there is no good substitute fuel. I would further admit that the fairly long-range outlook for natural gas is bleak, but this Nation and its people need to buy some time to develop alternate energy sources and I further believe that there is no present alternative that can supply the essential energy requirements of this Nation other than natural gas, oil, and coal for the near future.

Mr. Chairman, I, and most other Public Utility Commissioners, am prohibited from engaging in partisan political activity. However, I, personally, am a political animal and follow the campaigns of all potential presidential candidates. Each and every candidate is assuring the electorate that if he is elected, everyone who desires employment will have a job. It is my own personal view that the asperations of this Nation's people for a better economy will not be met unless an adequate energy supply is available. Therefore, I am for de-regulation of new supplies of natural gas - even though the price will no doubt be higher. De-regulation of new supplies of natural gas is no panacea, and by itself, will not solve our energy deficiencies. It is my judgment, however, that new supplies of natural gas are in the Nation's best interests. I know of no alternative to de-regulation.

STATEMENT OF
DON S. SMITH, COMMISSIONER
FEDERAL POWER COMMISSION

HEARINGS BEFORE THE
SUBCOMMITTEE ON ENERGY AND POWER
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
U. S. HOUSE OF REPRESENTATIVES

January 26, 1976

Chairman Dingell and Members of the Subcommittee on Energy and Power:

Just over a year ago the Federal Power Commission issued its Annual Report covering the Fiscal Year ending June 1974. The "Legislative Recommendations" section of that Report concluded with the assertion that:

> "[A]s a matter of top priority, this Commission believes that the Congress should consider and adopt legislation to divest the Commission of its statutory obligation to determine and fix producer rates for 'new gas' and establish a new framework for producer regulation." 1/

That section of the Report set out, by footnote, in part, the following:

> "Commissioner Smith recommends the deregulation of those producers who control individually less than one percent, and collectively less than 25 percent of the natural gas sold in interstate commerce. Twenty-five to thirty companies with larger market shares would remain subject

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1/ Fifty-Fourth Annual Report, Federal Power Commission, 1974, page 6.

> to FPC jurisdiction. By this action these producers could be regulated on a more rational and responsive basis than is currently possible, while retaining price surveillance over the bulk of the current supply."

My invitation to appear before the Energy and Power Subcommittee as it continued consideration of bills amending the Natural Gas Act with respect to producer price regulation was to elaborate on the foregoing statement. My views are my own and are neither endorsed nor shared by other members of the Commission. And the recommendations I make on legislative improvements to the Natural Gas Act do not signal my views on current administrative adjudications. Cases pending and cases impending must be decided on the basis of legislation as it is, rather than as it should be.

No observers of the Federal Power Commission's long efforts to exercise its wellhead gas pricing authority are happy with its results, nor with the tensions it has created. I agree that the Natural Gas Act should be

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2/ Id. at 5, n.2. Similar recommendations with similar qualifications appear in other public documents. See, e.g., National Gas Survey, Volume I, "The Commission Report", Federal Power Commission, 1975, page 3.

changed, and I do not claim wisdom not possessed by others who also are deeply concerned with the problem. We do have a shortage of available natural gas. Production levels are declining, curtailments are increasing, and proved inventories of deliverable supply are shrinking. There is debate over whether the quantitative measurements of this shortage are precise, but the existence of deteriorating trends is not in question. We are using less than we need but more than we are replacing.

At this point in its deliberation the Subcommittee has had presented to it exhaustive data on gas supply. I would highlight one aspect. Why the interstate market is not competing effectively for new supplies with the intrastate market should be no mystery to anyone who can tell the difference between 52 cents per Mcf 3/ and $1.50 per Mcf. The loss can be measured. Of a 1966 to 1974 proved reserve decline in the lower 48 States of 82 trillion cubic feet, 75 trillion cubic feet of this decline was borne by the interstate market. 4/

3/ See Opinion No. 699-H, "Just and Reasonable National Rates For Sales Of Natural Gas From Wells Commenced On Or After January 1, 1973 And New Dedications Of Natural Gas To Interstate Commerce On Or After January 1, 1973," 52 FPC ___, issued December 4, 1974. Opinion Nos. 699 *et seq.* were affirmed *sub nom.* *National Rate Cases for New Gas* (*Shell Oil Co.* v. *F.P.C.*), 520 F.2d 1061 (5th Cir. 1975).

4/ See Table 1.

Another, and perhaps more dramatic, way of illustrating the decline in interstate reserves may be seen from the amount of reserve additions dedicated to the interstate market during the same period. Table 2 shows "lower 48" total net gas reserve additions as reported by the American Gas Association (AGA) and net interstate reserve additions as reported by interstate pipelines to the FPC from 1966 through 1974. During the period 1966-1969 the inferred intrastate portion of total net reserve additions was about 27 percent. However, in the last 5 years there has been a dramatic shift in reserve additions away from the interstate market. From 1970 through 1974 only 5 percent of total net reserve additions were reported dedicated to the interstate market. In other words, 95 percent of total net reserve additions reported in the last 5 years has apparently been channeled into the intrastate market. 5/

Looking at "lower 48" reserve additions before revisions have been made to previous discoveries, Table 3 shows that the inferred intrastate new supply from 1966 to 1969 amounted to 16.5 Tcf or roughly one-third of the total reported by AGA

5/ According to a recent General Accounting Office Report to the Committee on Government Operations, House of Representatives, entitled Implications of Deregulating the Price of Natural Gas, at p. 9, 92 percent of reserve additions in the lower 48 States were dedicated to the intrastate market from 1970 to 1973.

for that same period. Since 1969 the indicated intrastate portion of new reserve additions has increased to nearly three-quarters (72.0 percent) of the total reported for the 1970-1974 period. I believe this trend has been abundantly clear for some time. We have been fortunate, indeed, that Mother Nature chose Federal waters under which to hide most of the major natural gas deposits that remain to be found. However, there have been a few significant finds onshore during the last five years, and the increments that can flow, if a window to onshore supplies is open to interstate users, are most important increments. Perhaps most importantly a large part of these supplies have flowed by virtue of various policies adopted by the Commission during the past few years as alternative and interim short-term responses to the shortage. Table 4 shows that over 58 percent of the total natural gas sales was committed to the interstate market under these "alternative" procedures between 1971 and the second quarter of 1975. Alternative procedures include (1) the optional certificate procedure 6/, (2) the limited term certificate procedure 7/

6/ Order Nos. 455 and 455-A, 48 FPC 218 and 477 (1972), *aff'd in part and rev'd in part sub nom*, *John E. Moss et al.* v. *F.P.C.*, 502 F.2d 461 (D.C. Cir. 1974), *cert. granted* *F.P.C.* v. *John E. Moss et al.*, 422 U.S. 1006 (1975).

7/ See Order No. 431, 45 FPC 570 (1971) and Order No. 431-A, 46 FPC 193 (1972), promulgating Section 2.70 of the Commission's Statement of General Policy and Interpretations, 18 C.F.R. 2.70 (1975).

(3) the 60 and 180 day emergency sales procedures 8/ , and (4) procedures applying to small producers. 9/

8/ See Order No. 402, 43 FPC 707 (1970) and Order No. 402-A, 43 FPC 822 (1970) promulgating Section 2.68 of the Commission's General Policy and Interpretations, 18 C.F.R. 2.68 (1975); Order No. 418, 44 FPC 1574 (1970) amending Sections 157.22 and 157.29 of the Commission's Regulations under the Natural Gas Act, 18 C.F.R. 157.22 and 157.29 (1975); Order Nos. 431 and 431-A, supra.

In this series of Orders, the Commission: (1) encouraged persons and companies exempt under Sections 1(b) and 1(c) of the Natural Gas Act to make emergency short-term sales or deliveries of natural gas in interstate commerce for up to 60 days without express Commission approval; and (2) provided for emergency sales by producers to pipelines and for emergency operations between pipelines for up to 60 days without prior certificate authorization under Section 7 of the Act.

The Commission extended the emergency sales procedures to 180 days by Order No. 491, 50 FPC 742 (1973), Order No. 491-A, 50 FPC 848 (1973), Order No. 491-B, 50 FPC 1463 (1973), and Order No. 491-C, 50 FPC 1634 (1973). Order Nos. 491 et seq. were set aside in Consumer Federation of America et al. v. F.P.C., 515 F.2d 347 (D.C. Cir. 1975), cert denied F.P.C. v. Consumer Federation of America et al., ___U.S.L.W ___ (October 14, 1975).

9/ See discussion infra at pp. 15-16.

Thus, less than half of the gas sales during the first half of this decade have resulted from the traditional long-term contracts under area and new national rate ceilings. While each nontraditional regulatory policy was controversial, and while I have been in some instances among their critics 10/, they did provide a structure whereby desparately needed increments were obtainable. However, I am not sanguine about the ability of the Commission to develop further new procedures to reach incremental supplies. Several procedures have been explicitly limited by the Courts which did so in terms which create some uneasiness about others.

10/ See "Order After Statutory Hearing Issuing Certificate Of Public Convenience And Necessity And Granting Petition To Intervene", Charles A. Barton, Sr. et al., Docket No. CI74-364, 51 FPC 1169 (1974); "Order Consolidating Proceedings, Setting Date For Hearing, Granting Interventions, And Denying Motion", William A. Jenkins (Operator), et al., Docket Nos. CI75-119 and RI75-5, 52 FPC ___ (October 3, 1974).

Chart I, taken from the FPC Office of Economics' latest Gas Supply Indicators, shows the estimated annual new sales of natural gas to interstate pipelines by certification procedure. The graph illustrates that the nontraditional procedures, i.e., limited-term, optional procedure, and 60-day emergency sales, are losing favor and cannot be relied upon for onshore supply increments to the interstate market. Legislative action must replace the regulatory ingenuity that is rapidly running its course.

I respectfully ask the Subcommittee to consider an approach to amending the Natural Gas Act which would exempt from the regulatory provisions of the Natural Gas Act the future interstate sales of "new gas" made by approximately 3,500 active small producers, and hopefully revitalize another 3,500 small producers who are no longer active in the new interstate supply field. Little, in terms of protective regulatory objectives, would be lost. Individually and collectively this group of producers cannot exert monopoly market control nor collect monopoly rates, the essential "window" to the intrastate market would be open for interstate consumers, and the regulatory work of the Commission could be focused where it needs to be focused, on the bulk of the supply. The prices that would obtain could become a credible measure of market value for large producer ratemaking.

Regulation limited to large producers would have substantial administrative, procedural, and economic advantages over the present system of regulation. It would no longer be necessary for the Commission to base its cost findings on outside data, mainly statistics from industry sources. Instead, the Commission would be able to use data compiled from regular reports filed by the large producers and subject to audit by the Commission's staff. Having access to company records on drilling and other operating and capital costs and on reserves would permit the Commission to do a more effective and expeditious job of rate regulation based on actual costs including reasonable profits. Noncost incentive allowances could be more confidently determined if the Commission were able to monitor the performance of the regulated companies, use its regulatory authority to stimulate improved performance, and assure that the use of any allowances was consistent with the objective sought.

The Commission would have the option of group ratemaking, individual company rate regulation, or a combination of the two. Group ratemaking for large producers would not have the infirmities of a national rate for all producers, such as the national rate recently established in Opinion No. 699 et seq. A group rate applied to large producers, each having geographically diversified operations and huge financial resources, is more equitable than a national rate applied to thousands of dissimilar companies, mostly very small operators with limited ability to spread their risks or withstand losses. If a group rate was established for large producers, the individual companies would each have an incentive to improve their efficiency over group average and, thus, earn more than average profits.

Under individual company rate regulation, the Commission would be able to evaluate each company's costs and return requirements and set rates which discriminate between incentive and windfalls. Careful consideration could be given to any special circumstances or requirements of individual companies. With 25 to 30 corporate entities to regulate, the Commission's case load would be more manageable than at present when the Commission is involved in cumbersome and costly national rate rulemaking plus the diminishing flow of optional certificate, limited-term certificate, and special relief cases.

A new regulatory plan might include elements from both of the above approaches. Flowing gas prices could be regulated on the basis of each company's actual costs, while a single incentive price for certificating new sales could be established for the group of large producers. The incentive price could be based on the estimated incremental cost of new gas supplies, recognizing that inflation as well as the need to extend the margin of production will require a higher price than the average cost of previously discovered gas. A single incentive price would most likely be deemed appropriate for new gas because the prospective cost of new gas should be the same for all large producers.

This approach, as the foregoing argues, would leave the Commission with a regulatory mission it could more adequately perform. It would relieve it of a problem it has yet to satisfactorily resolve.11/ Small producer regulation has been

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11/ See "Opinion And Order Determining Cost Of Service And Terminating Proceedings", Phillips Petroleum Company, Docket Nos. G-1148 et al., 24 FPC 537 (1960) where the Commission discussed the inherent problems involved in small producer regulation and stated (id. at 545-46):

> An illustration of the administrative impossibility of separate determinations for all producers' rates is found in the fact that there are 3,372 independent producers with rates on file with this Commission. The producers have on file with us 11,091 rate schedules and 33,231 supplements to these schedules. Currently, 570 of these producers are involved in 3,278 producer rate increase filings now under suspension and awaiting hearings and decisions. The number of completions of independent producer rate cases per man-year during the first 6 years following the Phillips decision indicate that nearly 13 years would be required for our present staff to dispose of the 2,313 cases pending on July 1, 1960. Within this 13-year period an additional estimated 6,500 cases would have been received.
>
> Thus, if our present staff were immediately tripled, and if all new employees would be as competent as those we now have, we would not reach a current status in our independent producer rate work until 2043 A.D.--eighty-two and one half years from now. Of course, we

troublesome to the FPC since the Phillips [12] decision. In Wisconsin v. F.P.C., 373 U.S. 294 (1963), Justice Clark, in a dissenting opinion, suggested that the Federal Power Commission exempt small producers from regulation. In Justice Clark's view this approach would allow the Commission to (id. at 330):

> . . . Concentrate on the large producers (20 of them control over 50% of the interstate gas) without the pressures incident to the smaller ones. The integrated producer of large volume is inevitably going to be the low cost producer. Hence, his rate will be an effective floor from

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11/ (Cont'd)

> could expect to improve our techniques and thus shorten the time required to process these cases. If we increased our efficiency one thousand percent, we would achieve current status in 1968--eight and two tenths years from now. And regardless of how much our staff is increased every case must still be reviewed by us and our own time and capacity is not unlimited. (Footnotes deleted.)

[12] Phillips Petroleum Company v. Wisconsin, 347 U.S. 672 (1954).

> which the small producer rates might well be adjusted. This would give the consumer rate protection over the overwhelming amount of interstate gas more quickly and would give assurances to the small producer that he would be protected from confiscation. 13/ (Footnote supplied.)

The Commission itself first addressed the small producer problem in its first Permian Basin Area Rate Proceeding 14/ and concluded that in order to expedite the administrative process and facilitate effective regulation it was necessary to afford small producers 15/ separate regulatory treatment. Although the Commission determined not to provide outright exemption for small producer sales, it concluded that the public interest would be served by

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13/ In F.P.C. v. Hunt, 376 U.S. 515 (1963), Justice Clark again suggested to the Commission that it consider some form of producer exemption from rate regulation.

14/ See Permian Basin Area Rate Proceeding (Permian I), 34 FPC 159, 234 (1965), aff'd sub nom Permian Basin Area Rate Cases, 390 U.S. 747 (1968).

15/ Small producers were defined as those producers whose total jurisdictional sales equalled less than 10 million Mcf annually.

eliminating separate certificate proceedings for small producer sales and by eliminating most reporting requirements. 16/ Small producer rates were limited, however, to the applicable area ceiling rate, but were released from the requirement that quality adjustments be made regarding the sale price.

The Supreme Court, in Permian Basin Area Rate Proceedings, 390 U.S. 747 (1968), upheld the Commission's treatment and classification of small producers finding such treatment and classification legally permissible under the Natural Gas Act and fully consistent with the Commission's statutory responsibilities.

16/ The Commission determined that total exemption for small producers would have been an illusion since the rates it established for the Permian area would tend to set the maximum prices small producers could obtain for their gas in that area.

In 1971, the Commission issued a series of orders [17] which set forth further exemptions for small producers. Under these orders the rates charged by small producers were no longer subject to direct regulation but were instead indirectly regulated through review of the purchased gas costs of the purchasing producers and/or pipelines. These orders further provided for a blanket certificate procedure for small producers and relieved them of most reporting requirements. Order Nos. 428 *et seq*. were set aside by the United States Court of Appeals for the District of Columbia Circuit in *Texaco, Inc.*, *et al*. v. *F.P.C.*, 474 F.2d 416 (1972) on the ground that the orders amounted to an unauthorized "deregulation" of small producer rates in contravention of the Natural Gas Act. That decision, however, was vacated by the Supreme Court in *F.P.C.* v. *Texaco, Inc*., *et al*., 417 U.S. 380 (1974). The Supreme Court found that under the Act the Commission is free to engage in indirect regulation of small producer rates as long as it insures that the ". . . rates paid by the pipelines, and ultimately borne by the consumer, are just and reasonable." The Supreme Court remanded the matter back to the Commission for further proceedings, however, because the orders did not provide sufficient guidance to the purchasing pipelines as to the standards that would be used in examining their purchases, nor did such orders emphatically state that the rates would be "just and reasonable."

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[17] See Order No. 428, 45 FPC 454 (1971), Order No. 428-A, 45 FPC 548 (1971), and Order No. 428-B, 46 FPC 47 (1971).

On August 28, 1975, the Commission issued Opinion No. 742 fixing small producer rates at 130 percent of the base ceiling rate for a comparable large producer sale.18/ The Commission found that small producers incur greater costs than large producers and, therefore, should be accorded a higher rate of return.19/ Thus, the Commission applied a 20 percent, as compared to a 15 percent, rate of return to the Opinion No. 699-H DCF analysis, and found that small producers should be allowed an increment of 30 percent over the nationwide or other base rate. That proceeding is currently pending before the Commission on rehearing.

18/ Any rate in excess of the 130 percent factor is to be indirectly regulated through the review of purchased gas costs in a pipeline rate proceeding.

19/ As the Commission noted in Opinion No. 742, these higher costs are partially a result of (1) less productivity, (2) higher ratio of dry holes, (3) the production of less condensate, (4) the prominence of farm-out arrangements, (5) the high percentage of exploratory and wildcat drilling, and (6) relative weaker credit standing.

Small producer deregulation requires the resolution of two major issues. The first is one of judgment, and requires a determination of the division between large and small producers that is rational in the context of what the legislation seeks to achieve. The second issue is personally more difficult for me, involving as it does a resolution of whether it is necessary to extend FPC jurisdiction to heretofore unregulated intrastate transactions by large producers.

Any legislation which segregates persons into two classes is subject to charges of discrimination or unfair treatment, unless the classification is reasonable.20/ I believe that legislation creating two classes of producers would be constitutional, and will furnish the Subcommittee staff with a legal analysis supporting my recommendation. If it is conceded that Congress can constitutionally take the classification approach, the question of which factors should be dispositive must be dealt with. My recommendation is that small producers be defined as those whose total marketed production of natural gas does not exceed 100 million Mcf per year. Using statistics derived essentially from reports filed with the Commission, and which are subject to being updated, this cutoff would deregulate no producer who individually controls as much as

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20/ McLaughlin v. Florida, 379 U.S. 184, 191 (1964).

one percent of total marketed production. Collectively, these small producers control in the neighborhood of 25 percent of the interstate market. Consequently, the classification could be said to exclude from regulation those producers who cannot pose a threat of monopoly power which regulation needs to address.

The second major issue this approach must confront is the necessity to equalize the natural gas markets. I believe, for the reasons stated earlier, that it is possible for regulated large producers and unregulated small producers to both make contributions to a national market. But just as this cannot be achieved unless small producers are permitted to sell in a national market on the same terms they can make their gas available to intrastate purchasers, large producers cannot be afforded an unregulated market which offers compensations the national market does not. This entails asserting jurisdiction over large producer sales which are now intrastate transactions. Removal of the intrastate sales exemption for large producers cannot be accomplished without numerous administrative and legal problems, which must be recognized and dealt with in a manner which will be characterized as forthright by some and brutal by others. It would require:
(1) immediate extension and clarification of FPC data-gathering authority to include assimilation of all intrastate production

and sales data by regulated large producers; (2) certification of jurisdiction over new large producer sales that would otherwise qualify for the intrastate exemption; (3) assertion of jurisdiction over existing contracts as they expire; (4) the determination of a cutoff period, after resolving the requisite constitutional questions which are conditions precedent to this type of extension of Federal jurisdiction, after which large producer sales would require certification irrespective of pre-existing contract terms. This cutoff period might be in the five to ten year range, depending on what a reasonable adjustment period should be and which protective measures for existing transactions are deemed appropriate by Congress.

In removing the intrastate exemption for large producer sales, it is important to make it clear that current intrastate users would not be precluded from using the natural gas they depend on, nor that any effort would be made to discriminate against them in favor of other users. For certificate purposes it might be desirable for Congress to provide that "grandfather" protection be given to current large intrastate producer sales. Nor should assurances be made that price reductions to such users would automatically follow the extension of jurisdiction. I believe that much recent drilling for gas to satisfy intrastate needs has been at cost levels which could be justified only where higher intrastate rates could be commanded for the product, and, consequently, rate reduction could not be expected to follow. It is desirable that the unregulated small producer rate level achieved in a national market be used as an important reference point in determining the appropriate large producer rate.21/ Use of small producer unregulated market prices as an important but noncontrolling element for large producer ratemaking could ameliorate the cost/rate lag created by the necessity of using historical costs for present rates during inflation. Since the purpose of deregulation of small producers would not be to drive large producers out of the gas business, they should be regulated in such a manner as to offer inducements to stay in it. Threats of punitive pricing policies would stimulate investments shifts to something other than natural gas production.

21/ The legislation specifically should provide that unregulated small producer rates can be a factor in determining rates for large producers.

I have attempted to reduce my suggestions for amending the Natural Gas Act to more specific proposals, as follows:

(1) Section 1(b) of the Act should be amended so as to remove from the jurisdiction of the Federal Power Commission and, hence, from regulation, sales of natural gas that qualify as "independent producer sales" if the gas is produced from a well from which gas has not previously been sold in interstate commerce. Thus, an independent producer sale of gas from any newly completed well, whether or not the underlying acreage may have been dedicated to interstate commerce, and any gas that was sold previously in intrastate commerce would be exempt from FPC regulation.

An "independent producer" would be a "person" whose total marketed production of natural gas (plus the total marketed production of any affiliate) 22/ does not exceed 100 million Mcf per year. Excluded from this definition would be producers that derive ten percent or more of their revenues from gas pipeline or distribution activities, or are affiliated with companies deriving ten percent or more of their revenues from such activities. "Total marketed production" is intended to include all gas produced by such person or persons except

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22/ "Affiliate" is defined as any person directly or indirectly controlling, controlled by, or under common control with such other person.

"Control" means the actual or legal power to dominate or determine in any manner, directly or indirectly, the policy, business practices or decision-making process of any natural gas company.

that gas consumed by the producer in its own operations. The 100 million Mcf dividing line excludes from the category of independent producers the largest 20-25 producers along with their producing affiliates and the affiliates of pipeline and distribution companies. All sales by these large and affiliate producers whether in interstate or intrastate commerce would be subject to the Natural Gas Act. However, approximately 3,500-7000 independent producers, who collectively control approximately 25 percent of the natural gas supplied to the interstate market, would be exempted from FPC regulation.

An "independent producer sale" would be defined as a sale of natural gas, except sales from the federal domain offshore, that is produced by an independent producer and a sale in which no natural gas producer or producers other than independent producers have any interest in the proceeds or profits other than a royalty interest totaling not in excess of 20 percent. After the effective date of the Act an "independent producer sale" would include a sale of natural gas by a person other than an independent producer made pursuant to an executory contract if the present seller had been an inde producer and the sale had been an independent producer sale at the time of initial commencement of deliveries under the contract. "Independent producer sale" would not include a sale of natural gas that is produced from acreage in which the independent producer acquired an interest after date of enactment of the bill, if, prior to the acquisition by the independen producer, a discovery well had been drilled into the reservoir from which the natural gas is produced within a distance of two statute miles for offshore areas in the state domain and one statute mile for onshore areas.

The foregoing approach to the definition of "independent producer sales" would address three basic problems. First, it would preclude non-independent producers from holding any interest in the independent producer sale other than a royalty interest not exceeding 20%. The royalty interest could be either a base lease royalty or an overriding royalty retained by the transferor in a farmout transaction, but in no event could the sale qualify for exempt status if the total interests of natural gas producers other than independent producers in the sale exceed 20%. It would also require that the gas be produced by an independent producer (or agent thereof). Thus, where both non-independent producers and independent producers held joint working interests in a well, the sale by the independent producer would be exempt only if that producer executed a separate contract and satisfied the royalty interest test.

Second, this approach deals with the problem of transition from independent to non-independent producer status in the event that marketed production increases to annual volumes in excess of 100 million Mcf. Deliveries pursuant to all contracts executed while the producer was an independent producer would remain exempt; only the contracts executed after the year in which the transition occurred would be subject to the Natural Gas Act.

Third, this approach is designed to prevent non-independent producers from indirectly receiving an unregulated price or its near equivalent by selling reserves in place to an independent producer. Sales from such reserves would not be exempt from the Act. The test of whether sales of gas from acreage acquired by an independent producer from the large producer would be exempt is whether a discovery well had identified natural gas in the same reservoir at a point less than one mile (two miles offshore) from the independent producer's well prior to the time that the independent producer acquired the acreage. The distance test has the virtue of being an objective one, and is intended to provide as much certainty as possible for both seller and buyer, given the vagaries of knowledge about conditions under the surface of the earth.

The prices that are paid to independent producers by pipelines should fully flow through to purchasers. To do otherwise would create uncertainties which could frustrate the stimulation of exploration, development, and sales sought to be achieved.

(2) All other natural gas producers and all their sales, whether in interstate commerce or in intrastate commerce, 23/ should be subject to full Commission regulation. Accordingly, the Act should be amended so as to apply to natural gas producers' transportation of natural gas in interstate and intrastate commerce, to their sales in interstate and intrastate commerce of natural gas for resale for ultimate consumption for domestic, commercial, industrial, or any other use, and to natural gas companies engaged in such transportation or sale. 24/ A natural gas company would be defined as any company that does not qualify as an "independent producer".

As of the effective date of these proposed amendments, all new sales of natural gas in either interstate or intrastate commerce by "natural gas companies" would be subject

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23/ Intrastate commerce would be defined as commerce between points within the same state.

24/ Congress may wish to consider applying the provisions of the Natural Gas Act to direct sales by producers to consumers.

to regulation by the Commission under the terms of the Natural Gas Act. Furthermore, all pre-existing sales of gas by "natural gas companies" in intrastate commerce would become subject to Commission regulation. Upon the appropriate filings, such sales, under the terms of the contracts providing for such sales, would be certificated on a "grandfather" basis.

(3) The Commission should be empowered to require reporting by large producers, i.e., "natural gas companies," of transfers of reserves to independent producers to assist in the enforcement of the definition of what constitutes an independent producer sale. Furthermore, the Commission should be empowered to require an independent producer to file: (a) a report of any information that is relevant to a determination of whether such person is an independent producer; (b) a report of the volumes sold and such price received under independent producer sales during the preceding calendar year; and, (c) such other information as the Commission may find necessary for the evaluation of the exclusion of independent producer sales from the Act.

These changes in the present regulatory structure would, in my view, lead to very desirable results. First, the freeing of approximately 3,500-7,000 independent producers, who account for about 25 percent of the natural gas supplied to the interstate market, from FPC regulation is the most rapid and effective method of encouraging new entrants and increasing competition in the gas producing industry. It should hopefully lead to a maximization of the exploratory effort by a group of producers that already account for approximately 75 percent of exploratory drilling in the United States. Second, the regulation of both interstate and intrastate sales of natural gas by the 20-25 largest producers, who control the remaining 75 percent of the market, would accomplish several beneficial objectives. It would reduce the number of regulated producers to a level which could be regulated on a more rational and responsive basis than is currently possible, while retaining price surveillance over the bulk of the gas supply. It would also enable the interstate pipeline companies to effectively compete with the industrial gas markets in the producing states for new supplies of gas from onshore areas while at the same time result in smaller and more gradually increasing costs to the ultimate consumer than if a broader segment of the market were deregulated.[25]

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[25] Appendix A presents a "first cut" calculation of the direct cost impact of the proposed amendments. The calculation does not include indirect effects (e.g., potential displacement of higher cost fuels).

TABLE 1

LOWER 48 STATES YEAR-END RESERVES
INTERSTATE VS. INTRASTATE

Year	Total AGA Reserves 1/ (Tcf)	Interstate Reserves (Form 15) (Tcf)	Interstate Reserves (Form 15) (Percent)	Assumed Intrastate Reserves 2/ (Tcf)	Assumed Intrastate Reserves 2/ (Percent)
1966	283.2	195.1	69	88.1	31
1967	285.9	198.1	69	87.8	31
1968	278.6	195.0	70	83.6	30
1969	266.3	187.6	70	78.7	30
1970	255.6	173.5	68	82.1	32
1971	243.1	161.3	66	81.1	34
1972	230.2	146.9	64	83.3	36
1973	214.2	134.3	63	79.9	37
1974	201.3	120.5	60	80.8	40

1/ Excludes gas volumes in underground storage.

2/ Derived by assuming that intrastate reserves are equal to the difference between AGA reserves and reserves reported in Form 15.

TABLE 2

LOWER 48 STATE NET RESERVE ADDITIONS INTERSTATE VS. INTRASTATE

Year	Total Net AGA Reserve Additions (Tcf)	Net Interstate Reserve Additions (Form 15) (Tcf)	Net Interstate Reserve Additions (Form 15) (Percent)	Assumed Intrastate Reserve Additions 1/ (Tcf)	Assumed Intrastate Reserve Additions 1/ (Percent)
1966	19.2	14.1	73	5.1	27
1967	21.1	14.8	70	6.3	30
1968	12.0	9.5	79	2.5	21
1969	8.3	6.0	72	2.3	28
1970	11.1	0.1	1	11.0	99
1971	9.4	1.9	20	7.5	80
1972	9.4	(0.2)	0	9.6	100
1973	6.5	1.2	18	5.3	82
1974	8.3	(0.8)	0	9.1	100

1/ Derived by assuming that intrastate reserve additions are equal to the difference between total AGA reserve additions and the reserve additions committed to the interstate market.

TABLE 3

LOWER 48 STATE TOTAL RESERVE ADDITIONS
INTERSTATE VS. INTRASTATE

Year	AGA Reserve Additions Excluding Revisions	Interstate New Supply (Form 15)		Assumed Intrastate New Supply 1/	
	Tcf	Tcf	%	Tcf	Percent
1966	14.8	10.0	68	4.8	32
1967	14.8	9.9	67	4.9	33
1968	9.8	6.4	65	3.4	35
1969	9.6	6.2	64	3.4	36
1970	11.3	3.5	31	7.8	69
1971	11.1	2.2	20	8.9	80
1972	10.7	5.0	47	5.7	53
1973	10.1	1.7	17	8.4	83
1974	9.7	2.4	25	7.3	75

1/ 1/ Derived by assuming that intrastate reserve additions are equal to the difference between total AGA reserve additions and the reserve additions committed to the interstate market.

Table 4

Natural Gas Sales Committed to the Interstate Market, 1971-1975 (2nd Qtr.)

	National Rate Ceiling Deliveries 6/ (000,000 Mcf)	National Rate Ceiling Av. Price 7/ (¢/Mcf)	Long-Term Contracts: Area Rate Ceilings 1/ Deliveries 6/ (000,000 Mcf)	Long-Term Contracts: Area Rate Ceilings 1/ Av. Price 7/ (¢/Mcf)	Long-Term Contracts: Optional Procedure 2/ Deliveries 6/ (000,000 Mcf)	Long-Term Contracts: Optional Procedure 2/ Av. Price 7/ (¢/Mcf)	Limited-Term Sales 3/ Deliveries 6/ (000,000 Mcf)	Limited-Term Sales 3/ Av. Price 7/ (¢/Mcf)	Small Producer Sales 4/ Deliveries 6/ (000,000 Mcf)	Small Producer Sales 4/ Av. Price 7/ (¢/Mcf)	Estimated Total Annual Deliveries 6/ (000,000 Mcf)	Estimated Total Annual Av. Price 7/ (¢/Mcf)	Emergency Sales 5/9/ 60-Day Sales Deliveries 8/ (000,000 Mcf)	Emergency Sales 5/9/ 60-Day Sales Av. Price 7/ (¢/Mcf)	Emergency Sales 5/9/ 180-Day Sales Deliveries 10/ (000,000 Mcf)	Emergency Sales 5/9/ 180-Day Sales Av. Price 7/ (¢/Mcf)
1971- 1st qtr.	-	-	37	22.79	-	-	-	-	-	-	37	22.79	79	31.74	-	-
2nd qtr.	-	-	65	21.77	-	-	41	33.46	-	-	106	26.29	39	34.08	-	-
3rd qtr.	-	-	132	22.51	-	-	104	32.83	-	-	236	27.06	36	34.33	-	-
4th qtr.	-	-	172	24.21	-	-	61	34.97	-	-	233	27.03	18	33.05	-	-
Total	-	-	406	23.87	-	-	206	33.59	-	-	612	27.14	172	32.94	-	-
1972- 1st qtr.	-	-	117	24.29	-	-	90	34.23	22	25.95	189	27.11	19	35.36	-	-
2nd qtr.	-	-	295	24.61	-	-	51	34.89	87	29.06	433	26.71	28	34.65	-	-
3rd qtr.	-	-	66	24.99	-	-	138	33.30	63	34.02	267	31.42	24	34.78	-	-
4th qtr.	-	-	49	24.03	1	26.50	121	35.59	58	38.67	229	33.86	17	32.58	-	-
Total	-	-	527	24.54	1	26.50	360	34.39	230	32.53	1118	29.36	88	34.43	-	-
1973- 1st qtr.	-	-	124	23.38	-	-	113	37.07	36	41.07	273	31.38	35	41.34	-	-
2nd qtr.	-	-	71	25.18	36	45.00	74	40.99	37	42.29	218	36.72	36	47.97	-	-
3rd qtr.	-	-	50	25.68	42	35.00	76	41.76	53	45.67	221	37.77	45	48.34	21	50.66
4th qtr.	-	-	21	27.46	9	40.42	77	45.83	55	48.79	162	44.15	-	-	87	53.77
Total	-	-	266	24.63	87	39.93	340	40.05	181	45.01	874	36.68	116	46.11	108	53.15
1974- 1st qtr.	-	-	25	24.52	29	41.77	53	41.21	38	51.54	145	41.15	-	-	88	61.85
2nd qtr.	40	51.50	22	28.05	-	-	41	42.73	42	51.07	145	45.34	16	58.85	-	-
3rd qtr.	177	43.68	-	-	13	45.00	-	-	42	57.47	232	46.25	11	74.72	-	-
4th qtr.	52	48.84	1	25.41	12	42.29	13	56.00	32	58.70	110	51.63	38	79.26	-	-
Total	269	45.83	48	26.15	54	42.04	107	43.58	154	54.42	632	45.01	65	73.46	88	61.85
1975 1st qtr.	191	52.45	2	24.26	2	53.32	1	63.53	19	63.54	217	53.22	16	83.40	-	-
2nd qtr.	55	54.14	-	-	-	-	1	60.0	37	83.59	93	66.04	20	93.66	-	-
3rd qtr.																
4th qtr.																
Total	248	52.87	2	24.26	2	53.32	2	61.77	56	76.79	310	57.07	36	89.10	-	-
1971 - 1975 (2nd qtr.) Total	517	49.21	1249	24.40	144	41.04	1015	37.41	621	45.59	3546	36.14	477	46.18	196	57.06

NOTE: Data are rounded and do not always add to totals shown. Volumes estimated by multiplying anticipated monthly or daily quantities by term. Actuals used where available.

1/ Area rate ceilings established in Commission Orders issued as follows: Hugoton-Anadarko (Op. 586), September 18, 1970; Appalachia (Order 411), October 2, 1970; Texas Gulf Coast (Op. 595), May 5, 1971; Rocky Mountain (Order 435), July 15, 1971; Southern Louisiana (Op. 598), July 16, 1971; Other Southwest (Op. 607), October 29, 1971; Permian Basin (Op. 662), August 7, 1973. Also includes sales in Permian Basin under paragraph 12, Docket No. R-389A, issued July 17, 1970.

2/ Order No. 455, issued August 3, 1972.

3/ Order No. 431, issued April 15, 1971.

4/ Order No. 428-C, issued April 14, 1972.

5/ Order No. 418 (60-day sales) issued December 10, 1970.

6/ Anticipated annual sales volumes.

7/ Initial prices weighted by volumes.

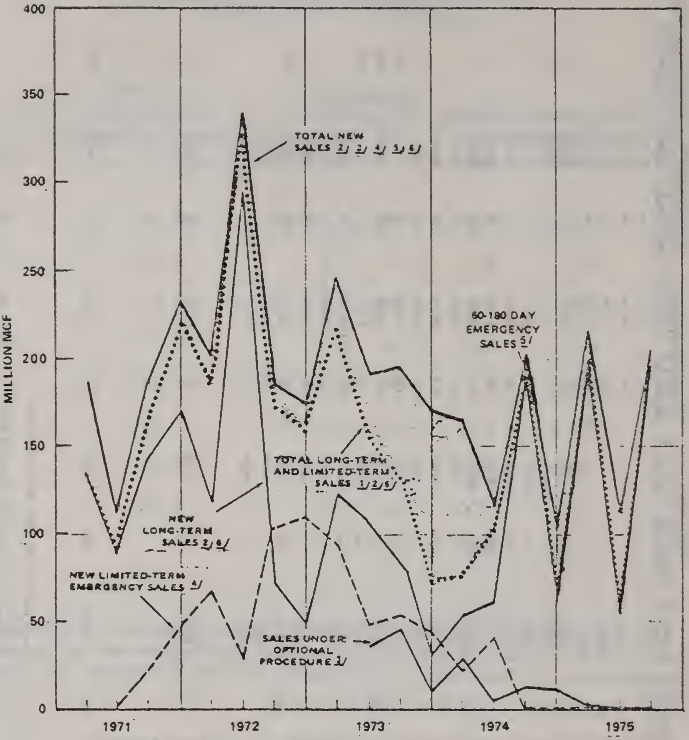
8/ Anticipated deliveries during indicated period.

9/ The procedures for emergency and limited term sales were discontinued on June 21, 1974, by Opinion No. 699 and reinstated on September 9, 1974, by Opinion No. 699B.

10/ Actual deliveries

Chart I

ESTIMATED ANNUAL NEW SALES OF NATURAL GAS BY LARGE AND SMALL PRODUCERS TO INTERSTATE PIPELINE COMPANIES 1971–1975



ESTIMATED ANNUAL SALES BY LARGE AND SMALL PRODUCERS UNDER NEW LONG-TERM AND LIMITED-TERM EMERGENCY GAS CONTRACTS (Million MCF)

Qtr.	Long-Term	Limited-Term	Total	Long-Term	Limited-Term	Total	Long-Term *	Limited-Term	Total	Long-Term	Limited-Term	Total	Long-Term	Limited-Term	Total
1st	134.5	-	134.5	118.1	67.9	186.0	123.6	93.2	216.8	53.6	22.4	76.0	197.8	1.1	199.3
2nd	88.9	1.8	90.7	296.0	29.3	325.3	106.6	47.9	154.6	51.6	41.0	132.7	57.1	.1	58.2
3rd	142.3	23.2	165.5	71.0	102.2	173.2	78.2	52.6	130.8	190.6r	—	190.6r	196.4	—	196.4
4th	170.0	48.7	218.7	49.4	109.1	158.5	30.1	43.1	73.2	54.5	4.5	59.0			
Total	535.7	73.7	609.4	534.5	308.4	842.9	338.5	236.8	575.3	370.3r	67.9	438.2r			

Source: FPC, Bureau of Natural Gas.

1/ Long-term contracts generally provide for a 15 to 20 year term while limited-term emergency contracts usually provide for a one to three year term. Limited-term emergency contracts were permitted under Order No. 431 issued April 15, 1971. Certificate authority for limited-term sales was rescinded by Opinion No. 699 issued June 21, 1974, in Docket No. R-389-B and reinstated by Opinion No. 699-B issued September 9, 1974.
Note: Annual new contract volumes based on estimated first month deliveries, as shown in rate schedule billing statements, multiplied by twelve.

2/ Excludes estimated new sales by small producers authorized in "CS" dockets as provided in Order Nos. 428 and 428-C issued March 18, 1971, and April 10, 1972, respectively, in Docket No. R-393.

3/ There were no sales authorized under the Optional Certification Procedure pursuant to Order No. 455 issued August 3, 1972, in Docket No. R-441 during the 3rd quarter of 1975.

4/ Excludes small producer sales under "CS" dockets and sales volumes under extensions to previously authorized limited-term sales.

5/ Sixty-day emergency sales by producers to interstate pipelines were permitted under Order No. 418 issued December 10, 1970. Authority for this type of sale was rescinded by Opinion No. 699 issued June 21, 1974, and reinstated by Opinion No. 699-B issued September 9, 1974. One-hundred eighty day emergency sales were allowed under Order No. 491 issued September 14, 1973, and terminated March 15, 1974, by Order No. 491-D issued March 1, 1974. Note: 60-180 day emergency sales volumes are not annual volumes. They are estimated by multiplying anticipated daily quantities by the agreement term; estimated 60-180 day sales prior to the 3rd quarter 1974 have been revised in this report to reflect actual sales volumes. The 60-180 day emergency sales consist of sales by both producers and intrastate pipelines to interstate pipelines and are only included in Total New Sales.

6/ Third quarter 1975 estimated long-term sales authorized under Opinion No. 699, as amended, amounted to 106,323 MMcf of which 34,254 MMcf are in contracts with terms of 5 years or less and 71,293 MMcf are in contracts with terms ranging from more than 5 years to 10 years.

Note: r-revised

APPENDIX A

AN ESTIMATE OF THE IMPACT OF AN INDEPENDENT PRODUCER EXEMPTION ON PRICES PAID BY INTERSTATE CONSUMERS

1. Assume that an average of approximately 30 percent of new gas sales for the next five years would be exempted. The assumed percentage of the unregulated portion of the interstate market is assumed to increase as follows:

   1st Year - 23%
   2nd Year - 26%
   3rd Year - 29%
   4th Year - 32%
   5th Year - 35%

2. Assume that 5 percent of annual volumes in the interstate market represent the current year's new gas sales; 23 percent of 5 percent equals 1.15 percent, which is the proportion of the first year's sales that would be affected. The proportion exempted would then grow as follows:

PERCENTAGE DISTRIBUTION

	Controlled "Old"	Controlled "New"	Exempt
1st Year	95	3.85	1.15
2nd Year	90	7.40	2.60
3rd Year	85	10.61	4.39
4th Year	80	13.60	6.40
5th Year	75	16.25	8.75

3. Assume the following prices per Mcf:

   Controlled "Old" - $ .30 (Opinion 749 post-July, 1976, average prices including taxes)
   Controlled "New" - $ .56 (Opinion 699-H including taxes)
   Exempt - $2.00

   The resulting prices are shown below:

	No Exemption	With Exemption
1st Year	31.3	33.0
2nd Year	32.6	36.3
3rd Year	33.9	40.2
4th Year	35.2	44.4
5th Year	36.5	49.1

4. As a percentage of the wellhead price, the increase due to the exemption may be estimated as follows:

	Actual Increase	Percent Increase
1st Year	1.66	5.3
2nd Year	3.74	11.5
3rd Year	6.32	18.6
4th Year	9.22	26.2
5th Year	12.60	34.5

5. Assume that wellhead cost is one-fourth of cost of gas to residential consumers. Then, the increase in the average residential bill would be one-fourth of the above percentages (e.g., about 8.6 percent in the 5th year).

6. The increase to all gas consumers can be estimated by multiplying the actual increase per Mcf by the assumed interstate quantities. If interstate quantities from domestic producers of 13 billion Mcf are assumed, the cost would be:

	Annual Cost (Millions of Dollars)
1st Year	195.8
2nd Year	486.2
3rd Year	821.6
4th Year	1,198.6
5th Year	1,638.0

UNITED STATES GENERAL ACCOUNTING OFFICE
WASHINGTON, D.C. 20548

FOR RELEASE ON DELIVERY
EXPECTED AT 11:30 AM
MONDAY, JANUARY 26, 1976

STATEMENT OF
HENRY ESCHWEGE, DIRECTOR
RESOURCES AND ECONOMIC
DEVELOPMENT DIVISION
BEFORE THE
SUBCOMMITTEE ON ENERGY AND POWER
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
HOUSE OF REPRESENTATIVES

AMOUNT OF NATURAL GAS THAT COULD BE RELEASED FROM FEDERAL PRICE REGULATIONS UPON EXPIRATION OF CONTRACTS FROM 1975 THROUGH 1985

MR. CHAIRMAN AND MEMBERS OF THE SUBCOMMITTEE:

WE ARE HERE AT YOUR REQUEST TO DISCUSS DATA WE COMPILED LAST YEAR ON THE AMOUNT OF NATURAL GAS THAT COULD BE RELEASED FROM REGULATION UPON EXPIRATION OF CONTRACTS FROM 1975 TO 1985. THIS IS AN AREA OF INCREASING CONCERN TO THE CONGRESS AS IT CONSIDERS THE IMPACT OF NATURAL GAS DEREGULATION ON CONSUMERS.

ON SEPTEMBER 8, 1975, THE COMPTROLLER GENERAL ISSUED A REPORT (RED-76-11) TO SENATOR HENRY M. JACKSON AND CONGRESSMAN JOHN E. MOSS. WE WERE ASKED TO PROVIDE INFORMATION ON THE FOLLOWING FOUR AREAS.

--VOLUMES OF NATURAL GAS, UNADJUSTED FOR PRODUCTION DECLINE, TO BE RELEASED UNDER EXPIRING CONTRACTS FOR EACH YEAR FROM 1975 THROUGH 1985 AND CUMULATIVELY,

--SAME VOLUMES OF GAS AS ABOVE BUT WITH ADJUSTMENTS FOR PRODUCTION DECLINE,

--AMOUNT OF GAS UNDER CONTRACTS WITH INDEFINITE PRICING CLAUSES, AND

--ADEQUACY OF THE FEDERAL POWER COMMISSION (FPC) DATA USED IN PROJECTING THE VOLUMES OF GAS TO BE RELEASED FROM CONTRACT.

GAS TO BE RELEASED FROM CONTRACTS

THE NATION'S NATURAL GAS PRODUCTION FOR INTERSTATE COMMERCE PEAKED DURING 1971 AND 1972 AT 14.2 TRILLION CUBIC FEET (TCF) AND HAS BEEN DECLINING SINCE THEN. MOST GAS SOLD IN INTERSTATE COMMERCE IS SOLD UNDER LONG-TERM CONTRACTS BETWEEN PRODUCERS AND INTERSTATE PIPELINE COMPANIES. EVEN THOUGH THE CONTRACTS USUALLY EXPIRE IN 20 YEARS, THE GAS CONTINUES TO FLOW UNTIL THE OPERATION BECOMES UNECONOMICAL AND FPC AUTHORIZES ABANDONMENT OF OPERATIONS. UPON EXPIRATION OF THE PRIMARY 20-YEAR CONTRACT, PRODUCERS AND INTERSTATE PIPELINES GENERALLY NEGOTIATE NEW CONTRACTS WHICH ARE ALSO SUBJECT TO FPC APPROVAL.

IN AUGUST 1973 FPC REQUIRED LARGE PRODUCERS TO REPORT THEIR 1972 SALES VOLUMES AND CONTRACT DATES AND TERMS FOR EACH CONTRACT ON FILE WITH FPC. ON THE BASIS OF THIS DATA WHICH RECEIVED LIMITED VERIFICATION AND WAS SOMEWHAT INCOMPLETE, WE ESTIMATED THE VOLUME OF GAS THAT MIGHT BE RELEASED FROM CONTRACTS EXPIRING DURING THE PERIOD FROM 1975 TO 1985.

IF THE LAW WERE TO REMOVE THE PRICE REGULATION OVER NATURAL GAS, THE VOLUME OF GAS RELEASED FROM CONTRACT MAY ALSO BE FREED FROM PRICE CONTROLS. WE REPORTED THAT UPON THE EXPIRATION OF SALES CONTRACTS AN ESTIMATED 29 TCF OF NATURAL GAS COULD BE RELEASED FROM REGULATION OVER THE PERIOD 1975-85. THIS ESTIMATE ASSUMES THAT THE PRODUCTION FROM EXISTING WELLS CONTINUES AT A CONSTANT RATE.

AS YOU KNOW, HOWEVER, GAS DOES NOT CONTINUE TO FLOW FROM RESERVOIRS AT A CONSTANT RATE INDEFINITELY. THEREFORE, ANY PROJECTION OF THE GAS AVAILABILITY IN THE FUTURE DEPENDS ON THE RATE AT WHICH GAS WILL BE FORCED FROM THE RESERVOIR.

THREE METHODS WHICH HAVE BEEN DEVELOPED OVER THE PAST SEVERAL YEARS--THE DAVIS DECLINE CURVE, THE NATIONAL AVAILABILITY CURVE (NAC), AND THE TOTAL ENERGY RESOURCES ANALYSIS (TERA) CURVE--CAN BE USED TO DETERMINE AT WHAT RATE PRODUCTIVITY FROM EXISTING RESERVOIRS WILL DECLINE.

OUR REPORT DISCUSSED EACH OF THESE CURVES AND CONCLUDED THAT THE CUMULATIVE VOLUME OF GAS THAT WOULD BE RELEASED FROM REGULATION OVER THE 1975-85 PERIOD WOULD BE 9.1 TCF ASSUMING THE DAVIS DECLINE CURVE, 12.7 TCF ASSUMING THE NAC METHOD, AND 7.7 TCF ASSUMING THE TERA CURVE.

AMOUNT OF GAS UNDER CONTRACT WITH INDEFINITE PRICING CLAUSES

INDEFINITE PRICING CLAUSES INCLUDED IN MANY OF THE CONTRACTS BETWEEN PRODUCERS AND INTERSTATE PIPELINES PROVIDE FOR FUTURE CHANGES IN THE PRICE OF GAS SOLD, DEPENDING ON CERTAIN ECONOMIC FACTORS OCCURRING. SOME INDEFINITE PRICING CLAUSES MAY HAVE AN EFFECT ON THE AMOUNTS OF GAS THAT WOULD BE FREED FROM PRICE CONTROLS IF DEREGULATION LEGISLATION WERE ENACTED. ASSUMING THIS OCCURS, THE AMOUNT OF GAS CURRENTLY UNDER CONTRACT WHICH WOULD BE DEREGULATED BECAUSE OF INDEFINITE PRICING CLAUSES WOULD DEPEND ON THE PROVISIONS OF THE DEREGULATING STATUTE AND/OR FPC RULEMAKING ACTIONS.

THE MORE COMMON TYPES OF INDEFINITE PRICING CLAUSES IN NATURAL GAS CONTRACTS FOLLOW.

--THE RENEGOTIATION CLAUSE ALLOWS FOR PRICE CHANGES AT SOME SPECIFIC TIME.

--THE REDETERMINATION CLAUSE IS SIMILAR TO THE RENEGOTIATION CLAUSE IN ITS EFFECT AND PROVIDES FOR PRICE ESCALATIONS TO THE FAIR-MARKET PRICE WHICH MAY BE HIGHER THAN THE FPC-ACCEPTED PRICE LEVEL.

--THE FAVORED-NATION CLAUSE ALLOWS FOR INCREASED RATES IF OTHER CONTRACTS IN THE AREA SPECIFY HIGHER RATES.

--THE DEREGULATION CLAUSE PERMITS HIGHER RATES IF REGULATORY CONTROL IS REMOVED.

--THE AREA RATE CLAUSE ALLOWS PRICES TO ESCALATE TO THE FUTURE FPC-ESTABLISHE RATES FOR THE AREA COVERED BY THE CONTRACT.

OF THE ABOVE CLAUSES, ONLY THE AREA RATE CLAUSE APPEARS TO BE PERMISSIBLE UNDER FPC REGULATIONS.

DATA FILED BY PRODUCERS SHOWED THAT ABOUT 33 PERCENT OF THE GAS WAS SOLD UNDER LONG-TERM CONTRACTS HAVING ONE OR MORE OF THE IMPERMISSIBLE INDEFINITE PRICING CLAUSES, WHILE 30 PERCENT OF THE GAS WAS SOLD UNDER CONTRACTS HAVING THE PERMISSIBLE AREA RATE CLAUSE.

RECENT TRENDS IN LONG-TERM CONTRACTING BY GAS PRODUCERS SEEM TO BE TOWARD INCLUDING DEREGULATION CLAUSES IN CONTRACTS. WE NOTED IN OUR REPORT THAT OVER HALF THE LONG-TERM CONTRACTS FILED WITH FPC IN RECENT MONTHS CONTAINED SUCH CLAUSES, PRESUMABLY ANTICIPATING SOME FORM OF GAS DEREGULATION BY THE CONGRESS.

BECAUSE FPC REGULATIONS (18 CFR 154.93) MAKE MOST INDEFINITE PRICING CLAUSES INOPERATIVE AND OF NO EFFECT AT LAW, FPC BELIEVES THAT LEGISLATION WHICH REMOVES PRICE CONTROLS ON NEW GAS WILL NOT NECESSARILY PERMIT GAS UNDER EXISTING CONTRACTS TO BE RELEASED FROM REGULATION BECAUSE OF SUCH CLAUSES.

I WANT TO REEMPHASIZE, HOWEVER, THAT THE AMOUNT OF GAS DEREGULATED BECAUSE OF INDEFINITE PRICING CLAUSES WOULD DEPEND ON PROVISIONS OF THE DEREGULATING STATUTE AND/OR COMMISSION RULEMAKING ACTIONS.

ACCURATE AND COMPLETE DATA NEEDED

OUR PROJECTIONS AS WELL AS THE PROJECTIONS OF FPC WERE BASED ON FPC SALES VOLUME DATA FOR A SINGLE YEAR--1972. THIS DATA WAS OBTAINED BY AN AUGUST 1973 FPC ORDER, ON A ONE-TIME ONLY BASIS AS PART OF A RULEMAKING PROCEDURE TO ESTABLISH JUST AND REASONABLE RATES FOR NATURAL GAS. NO OTHER DATA WAS AVAILABLE FOR PROJECTING THE AMOUNT OF GAS THAT WOULD BE RELEASED FROM PRICE CONTROLS IF DEREGULATION LEGISLATION WERE ENACTED.

TO INSURE THE PROJECTIONS' RELIABILITY, THE BASE YEAR DATA'S ACCURACY AND COMPLETENESS MUST BE VERIFIED. FPC DID ONLY LIMITED VERIFICATION OF THE DATA REPORTED. WE NOTED SEVERAL DIFFERENCES IN THE 1972 SALES DATA SUBMITTED BY PRODUCERS PURSUANT TO THE AUGUST 1973 ORDER AND THE 1972 SALES DATA THAT THEY SUBMITTED IN RESPONSE TO OTHER FPC REQUIREMENTS. FPC WAS AWARE OF SOME OF THE DIFFERENCES BUT COULD NOT EXPLAIN THEM.

FPC OFFICIALS STATED THAT DATA COLLECTION AND COMPILATION TOOK A YEAR AND 3 MONTHS BECAUSE OF (1) THE LARGE NUMBER OF REPORTS FILED, (2) INCORRECT OR INCOMPLETE DATA SUBMITTED BY THE PRODUCERS, NECESSITATING FOLLOWUP REQUESTS BY FPC, AND (3) FAILURE OF SOME PRODUCERS TO FILE THE DATA PROMPTLY.

NEVERTHELESS, THE FINAL RESULTS DID NOT CONTAIN ALL REQUIRED DATA. WE NOTED FOUR PRODUCERS WHO SIMPLY DID NOT FILE THE DATA REQUESTED AND MANY PRODUCERS WHO FILED INCOMPLETE DATA WHICH, IN SOME INSTANCES, WAS CRITICAL IN DETERMINING THE AMOUNT OF GAS THAT WOULD BE RELEASED FROM CONTRACT DURING CERTAIN PERIODS.

CONSIDERING THE TREND TOWARD SHORTER TERM CONTRACTS AND THE INCLUSION OF DEREGULATION CLAUSES, WE BELIEVE THAT FPC MUST MAINTAIN CURRENT INFORMATION SO THAT NEEDED DATA IS READILY AVAILABLE FOR USE IN FUTURE CONGRESSIONAL AND FPC DECISIONMAKING.

WE RECOMMENDED THAT THE CHAIRMAN, FPC, IMPLEMENT PROCEDURES TO ENSURE THAT DATA ON THE STATUS OF GAS FLOWING UNDER CONTRACTS IS REASONABLY CURRENT AND RELIABLE.

THE CHAIRMAN, FPC HAS INITIATED ACTION TO IMPLEMENT OUR RECOMMENDATION. ON DECEMBER 17, 1975, THE COMMISSION ISSUED NOTICE OF PROPOSED RULEMAKING, DOCKET NO. RM76-10, WHICH IF ADOPTED, WOULD REQUIRE NATURAL GAS COMPANIES TO FILE A FORM SHOWING THE AMOUNT OF GAS FLOWING IN INTERSTATE COMMERCE. THE FORM WILL ALSO PROVIDE (1) A DETAILED BREAKDOWN OF THE IMPORTANT PROVISIONS OF ALL RATE SCHEDULES ON FILE WITH THE COMMISSION, (2) A BASIS FOR ESTIMATING THE REVENUE IMPACT OF NATIONWIDE AND/OR AREA RATEMAKING PROPOSALS BY PRICING AREA, STATE AND PURCHASER, AND (3) A MEANS OF DETERMINING THE POTENTIAL EFFECTS OF PERIODIC PRICE ESCALATIONS AND INDEFINITE PRICING PROVISIONS.

THE NEW FORM ENCOMPASSES SEVEN SCHEDULES WHICH AFTER INITIAL FILING WILL BE FILED ANNUALLY OR AS CHANGES OCCUR DEPENDING UPON THE TYPE OF INFORMATION INVOLVED.

MR. CHAIRMAN, THIS COMPLETES MY PREPARED STATEMENT; WE WILL BE GLAD TO RESPOND TO YOUR QUESTIONS.

[illegible] — Not to be released outside the General [illegible] Office except on the basis of specific approval by the Office of Congressional Relations.

REPORT OF THE
COMPTROLLER GENERAL
OF THE UNITED STATES

Reliable Contract Sales Data Needed For Projecting Amounts Of Natural Gas That Could Be Deregulated

Federal Power Commission

This report provides data on the amount of natural gas under contract which could be expected to be released from Federal price regulations when contracts expire between producers and interstate pipelines from 1975 through 1985.

GAO recommended that FPC take action insuring that such data is current and reliable. FPC used 1972 data to study deregulation effects. Data reliability was questionable because FPC did only limited verification to determine it was complete and accurate.

RED-76-11 SEPT. 8, 1975

COMPTROLLER GENERAL OF THE UNITED STATES
WASHINGTON, D.C. 20548

B-178205

The Honorable Henry M. Jackson
United States Senate and
The Honorable John E. Moss
House of Representatives

This is our report on reliable contract sales data needed for projecting amounts of natural gas that could be deregulated, Federal Power Commission. Our review was undertaken in response to your joint request for information on interstate pipeline company contracts including data on the amount of natural gas which could be released from Federal regulations upon expiration of contracts from 1975 to 1985.

We invite your attention to the fact that this report contains a recommendation to the Chairman of the Commission which is set forth on page 17. As you know, section 236 of the Legislative Reorganization Act of 1970 requires the head of a Federal agency to submit a written statement on actions taken on our recommendations to the House and Senate Committees on Government Operations not later than 60 days after the date of the report and to the House and Senate Committees on Appropriations with the agency's first request for appropriations made more than 60 days after the date of the report. We will be in touch with your office in the near future to arrange for the release of the report so that the requirements of section 236 can be set in motion.

Elmer B. Staats
Comptroller General
of the United States

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ABBREVIATIONS

BCF	billion cubic feet
FPC	Federal Power Commission
GAO	General Accounting Office
NAC	National Availability Curve
TCF	trillion cubic feet
TERA	Total Energy Resources Analysis

COMPTROLLER GENERAL'S REPORT TO
THE HONORABLE HENRY M. JACKSON
UNITED STATES SENATE AND
THE HONORABLE JOHN E. MOSS
HOUSE OF REPRESENTATIVES

RELIABLE CONTRACT SALES
DATA NEEDED FOR PROJECTING
AMOUNTS OF NATURAL GAS THAT
COULD BE DEREGULATED
Federal Power Commission

DIGEST

Several legislative proposals have been made to deregulate natural gas. GAO was asked to provide data on the amount of natural gas currently under contract which could be expected to be released from Federal price regulations upon expiration of contracts between producers and interstate pipelines from 1975 to 1985.

On the basis of Federal Power Commission data for 1972 which received limited verification and, in some cases, was incomplete, GAO has estimated the amount of natural gas which may be released during the period.

GAO is recommending that the Commission take action to ensure that such data is reasonably current and reliable. The Chairman of the Commission agreed to implement GAO's recommendation. (See pp. 17 and 18.)

Natural gas produced in the Nation to be sold in interstate commerce peaked during 1971 and 1972 at 14.2 trillion cubic feet. Annual interstate production in 1974 was 12.9 trillion cubic feet, a 9.2 percent decline from the 1972 level. Analysis of the Commission's contract sales data showed that about 29 trillion cubic feet of gas would be released from contract from 1975 to 1985 assuming a constant rate of production.

Gas does not flow from reservoirs at a constant rate indefinitely. Considering the production decline occurring over the life of a well, the amount of gas released from contract from 1975 to 1985 would range from 7.7 trillion cubic feet to about 12.7 trillion cubic feet, depending on which of the three most generally accepted production decline curves is used in the calculation. (See p. 3.)

Tear Sheet. Upon removal, the report cover date should be noted hereon.

Many sales contracts between producers and interstate pipeline companies contain indefinite pricing clauses which may affect the amount of gas released from price controls if deregulation occurs. The amount of gas deregulated because of indefinite pricing clauses would depend on provisions of the deregulating statute and/or Commission rulemaking actions. (See p. 12.)

The Commission used 1972 gas contract sales data to study the deregulation effects. GAO also used the 1972 data to make its computations. Reliability of such data was questionable because the Commission did only limited verification to determine that the data was complete and accurate.

Although the type of data the Commission obtained for 1972 was primarily for establishing just and reasonable gas rates, it became critical to the various deregulation studies on which important decisions may be based. (See p. 15.)

CHAPTER 1

INTRODUCTION

The Natural Gas Act of 1938 (15 U.S.C. 717) authorized the Federal Power Commission (FPC) to regulate companies which transport and sell natural gas in interstate commerce. The act is to ensure that the ultimate natural gas consumer receives the lowest reasonable rate and protection from exploitation. Intrastate sales--the gas that is used in the same State in which it is produced--are generally State regulated.

Before 1954, FPC construed the act as authorizing only the regulation of interstate gas sales by pipeline companies. In 1954 the Supreme Court in Phillips Petroleum Company v. Wisconsin held that FPC must also regulate prices charged by gas producers to interstate pipeline companies. Since then, FPC has, under the Natural Gas Act, regulated gas producer sales, to insure just and reasonable rates for these sales.

The natural gas industry is composed of three segments: production, transmission, and distribution. The industry is physically interconnected by a pipeline network extending through the lower 48 States and across the Mexican and Canadian borders.

At one end of the network are more than 7,000 producers, consisting of large petroleum companies most of whose production is sold in interstate commerce and of small independent producers much of whose production is sold in intrastate commerce. FPC has no jurisdiction over producers' operations but when gas is sold in interstate commerce for resale, it has the authority to determine whether the sales should be permitted in the interests of public convenience and necessity, and, if so, at what price and on what terms.

The transmission segment consists of over 100 interstate pipeline companies, whose operations are subject to FPC regulation, and intrastate pipelines, which are generally State regulated. By the end of 1972, more than 187,000 miles of transmission pipe had been constructed by FPC-regulated companies. FPC regulates both the price paid to producers by the pipelines and the price at which the pipelines sell it to distributors to insure that the pipeline companies meet their operating expenses and earn a return on investment in facilities, while at the same time protecting the consumer. State regulatory commissions generally serve a similar function in regulating intrastate pipelines.

Distribution comprises some 1,600 companies which sell most of the gas to the ultimate consumers. The distributors depend on FPC for protecting their ability to buy gas from interstate pipelines at fair prices and on reasonable terms. A few companies engage in production, transmission, and distribution activities, and many others engage in transmission and gas production.

Since the 1954 Supreme Court decision involving the Phillips Petroleum Company, attempts have been made to amend the Natural Gas Act to divest FPC of jurisdiction over natural gas sales by producers, thereby deregulating wellhead sales. In 1956 the Congress passed legislation exempting wellhead gas prices from direct FPC regulation; however, the President vetoed the bill.

More recent deregulation proposals by Members of Congress and FPC commissioners differ in the degree to which gas should be deregulated. Proposals range from total deregulation of all gas production to deregulation of gas not previously contracted for and of gas released upon expiration of sales contracts.

Senator Henry M. Jackson and Congressman John E. Moss asked us to review the terms of natural gas sales contracts. Specifically, after the request was modified (see app. II), we were asked to provide information on the

--volumes of natural gas, unadjusted for production decline, to be released under expiring contracts for each year from 1975 through 1985 and cumulatively,

--same volumes of gas as above but with adjustments for production decline according to various methods used with an explanation of these methods,

--amount of gas under contracts with indefinite pricing clauses, including comments on the various clauses and their prevalence in natural gas contracts, and

--adequacy of the FPC data used in projecting the volumes of gas to be released and of FPC's system for obtaining such data.

CHAPTER 2

GAS TO BE RELEASED FROM CONTRACTS EXPIRING FROM 1975 TO 1985

If the law removes the regulation over natural gas, existing gas supplies may also be freed from controls as contracts expire. We have computed the volume of gas that will be released from expiring contracts from 1975 to 1985 and therefore will potentially be available at deregulated prices. These computed volumes range from about 29 trillion cubic feet (TCF) to 7.7 TCF, depending on assumptions as to the rate of gas flow over the periods in which it is economically recoverable.

FPC DATA

The Nation's natural gas production for interstate commerce peaked during 1971 and 1972 at 14.2 TCF. Annual interstate production declined 3.5 percent in 1973 to 13.7 TCF and 5.8 percent in 1974 to 12.9 TCF; in 1975 it is about 8 percent below the 1974 level according to preliminary monthly data for the first few months of 1975. Most gas sold in interstate commerce is sold under long-term contracts, generally 20 years, between producers and interstate pipeline companies. Even though the contracts expire in 20 years, the gas wells do not necessarily stop production. Rather, the gas continues to flow until the operation becomes uneconomical and FPC authorizes abandonment of operations. Generally FPC does not maintain cumulative data on the volume of gas under contract and the expiration dates involved. However, in August 1973, it requested companies producing more than 10 billion cubic feet (BCF) of gas a year to provide it with 1972 sales volume data, including information on expiring contracts. Some pipeline affiliates and pipeline companies were also required to report expiring contract volume data.

FPC sought information for use in its consideration of a rulemaking procedure for establishing just and reasonable gas rates. Among other things, the order required large producers to report their 1972 sales volumes and contract dates and terms for each contract on file with FPC when sales commenced before January 1, 1973. The data represented the most current cumulative data available at FPC on volumes of gas under expiring contracts. Because of the large number of reports filed and incorrect or incomplete data submitted by producers, necessitating followup requests, FPC spent over a year gathering and tabulating the 1972 sales volume information. This task was completed in February 1975.

Before completing its summary, FPC used the 1972 data, in late 1974, to prepare preliminary data on gas volumes under expiring contracts. An FPC task force also used the 1972 data in preparing its January 1975 report, "A Preliminary Evaluation of the Cost of Natural Gas Deregulation."

To make our computations, we updated the 1972 FPC data to include about 52 BCF of estimated annual gas sales under contracts entered into in 1973 and 1974 which will expire during the 1975-85 period. Such shorter term contracts (10 years or less) have recently become more prevalent apparently because of the uncertainty over gas prices. Available FPC records showed that total gas volumes under producer contracts with terms of 10 years or less represented 17.6 and 22.6 percent of the total gas sold in the third and fourth quarters of 1974, respectively.

Using FPC's 1972 sales volume data and the 1973 and 1974 contract data described above, we prepared the following schedule showing the volumes of gas that would be released from contracts each year, the amount of gas that would be flowing each year where contracts had expired beginning in 1975, and the cumulative amount of gas that will be released from contracts during the 1975-85 period.

Expiring Interstate Contract Volumes for

1975-85 (note a)

Year of expiration (note b)	Volumes expiring	Total gas flowing (note c)	Cumulative volume released (note d)
	---------------------(BCF)---------------------		
1975	124		
1976	423	546	670
1977	376	922	1,592
1978	507	1,430	3,022
1979	781	2,210	5,232
1980	661	2,872	8,104
1981	667	3,538	11,642
1982	347	3,885	15,527
1983	32	4,267	19,794
1984	389	4,655	24,449
1985	304	4,960	29,409

[a] Volumes are based on an assumed constant production rate.

[b] Year in which the stated volumes first receive a whole year's exposure to any deregulatory proposal.

[c] May not add due to rounding.

[d] Includes cumulative volumes released in previous years plus amount flowing that year.

EFFECTS OF PRODUCTIVITY DECLINE ON GAS AVAILABILITY

Gas does not continue to flow from reservoirs at a constant rate indefinitely. Therefore, any projection of the gas availability in the future depends on the rate at which gas will be forced from the reservoir.

Three methods which have been developed over the past several years--the Davis decline curve, the National Availability Curve (NAC), and the Total Energy Resources Analysis (TERA) curve--can be used to determine at what rate productivity from existing reservoirs will decline.

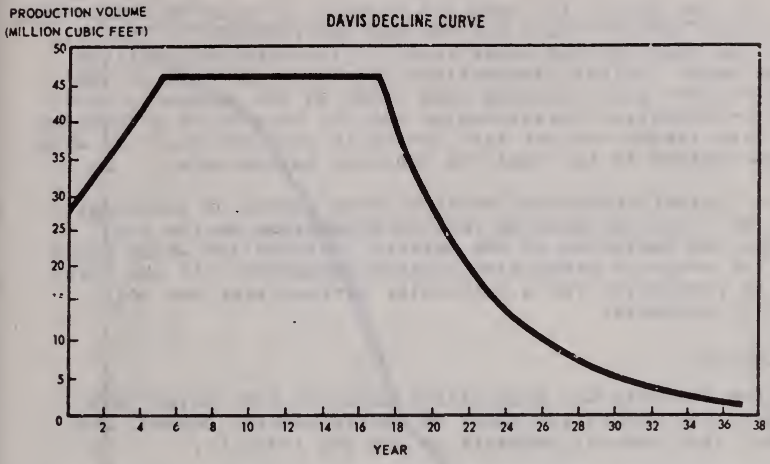
Davis decline curve

Mr. Warren B. Davis developed the Davis decline curve and presented it at an FPC hearing in the early 1960s relative to a petition for a rate increase by the Gulf Oil Corporation. The curve, based on the production pattern for the producer's operations, was used to project future revenues from the production of natural gas.

On September 25, 1968, FPC stated that the Davis decline curve provided a reasonably reliable estimate of gas production for determining future revenues. More recently, in January 1975, FPC used the Davis decline curve to estimate future production volumes for expiring contracts.

This curve assumes that individual gas reservoirs have a 37-year production life; it also assumes that production from such reservoirs increases during the first 5 years, remains constant from the fifth through the seventeenth years, and declines about 15 percent annually after that.

Using the Davis decline curve, theoretical gas production from a reservoir having 1 BCF of proved reserves is shown in the following graph.



NAC method

The FPC staff developed the NAC method during the early 1970s to help project the amount of natural gas that will be available through 1990.

The NAC method is a two-step procedure. The first step involves developing a curve which represents the maximum production capability of the average gas field at every stage of depletion. NAC was constructed by FPC staff from over 900 individual gas sources as reported in FPC Form 15, Annual Report of Gas Supply which is filed annually by interstate pipeline companies.

The second step involves segregating all reserves into "vintages" according to size and the year added to the inventory of previous and projected national reserves. The annual national production capability of the reserves existing in any given year is then calculated by first determining the productive capability of each vintage using NAC and then summing the productive capability of all vintages. Each vintage year has a different production decline pattern, with the most recent vintage years having a more rapid rate (7.5 percent) of production because of the increased demand for natural gas.

For our study, FPC used its computer program in determining the proper decline rates for various gas vintages at specific times and then applied those rates to the expiring contract volume data. Certain assumptions regarding the term of the contract, the year reserves were added to the inventory, the reserve-production relationship, and the more rapid production rate from recent shorter term contracts were necessary to adapt the NAC method to the expiring contract volume data.

A typical production decline curve cannot be graphically depicted since the decline rate is determined on the year the gas was dedicated to the market. Information which would show the complete production pattern beginning with the first year of production for a particular vintage year was not readily available.

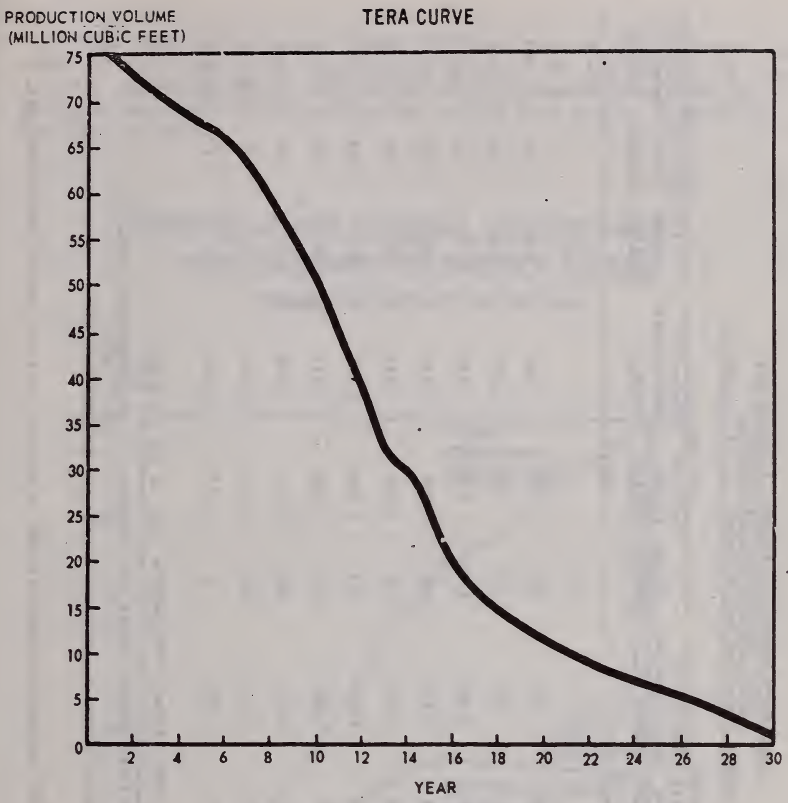
TERA curve

The American Gas Association designed TERA which is a computerized simulation model of energy supply, demand, and prices, with special emphasis on the gas industry.

A submodel of TERA, TERA Wellhead Deliverability and Pricing Submodel, employs a production decline curve which we will refer to as the TERA curve. The TERA curve is a modification of the NAC and assumes that production declines on a percentage basis. The American Gas Association does not accept, however, that gas production declines according to the smoothness of NAC.

The TERA curve does assume that any given well will produce 95 percent of its ultimate production within 30 years. When using the curve, the American Gas Association does not consider any production after 30 years.

Using the TERA curve, theoretical production of gas from a reservoir having 1 BCF of proved reserves is shown on the following graph.



TERA CURVE

Gas to be released from expiring contracts assuming production decline

The following schedule shows the amount of gas that would be released under expiring contracts from 1975 to 1985, both annually and cumulatively, using various production decline curves.

Comparative Schedule of Volumes of Natural Gas Under Expiring Contracts Assuming Various Production Decline Methods for 1975-85 Period

Year of expiration (note b)	Davis curve			NAC (note a)			TERA curve		
	Volumes expiring	Total gas flowing (note c)	Cumulative volume released (note d)	Volumes expiring	Total gas flowing (note c)	Cumulative volume released (note d)	Volumes expiring	Total gas flowing (note c)	Cumulative Volume Rel. (note d)
	(BCF)								
1975	76			93			83		
1976	224	290	366	306	387	480	243	318	401
1977	168	416	782	261	598	1,078	188	474	875
1978	230	584	1,366	339	858	1,936	215	638	1,513
1979	350	849	2,215	497	1,239	3,175	262	828	2,341
1980	311	1,034	3,249	410	1,480	4,655	225	956	3,297
1981	299	1,185	4,434	393	1,668	6,323	170	1,008	4,305
1982	156	1,170	5,604	198	1,630	7,953	81	954	5,259
1983	171	1,169	6,773	209	1,607	9,560	76	889	6,148
1984	175	1,175	7,948	207	1,584	11,144	72	811	6,959
1985	138	1,143	9,091	8	1,517	12,661	55	717	7,676

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[a] Volumes derived from FPC staff's application of NAC decline rates to the input data.

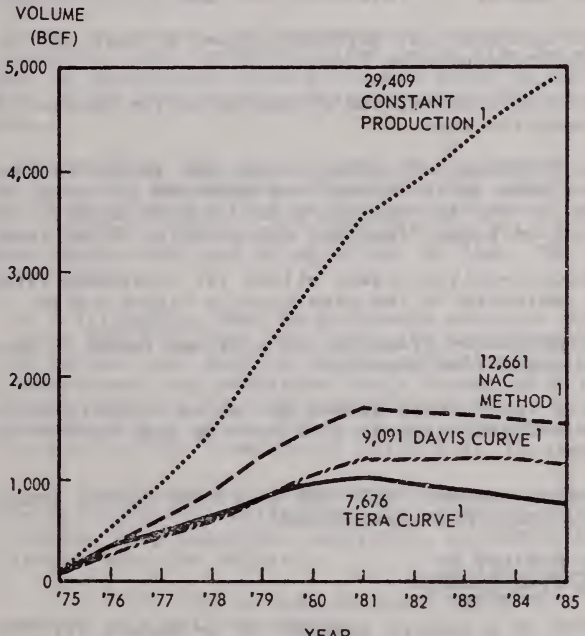
[b] Year in which the stated volumes first receive a whole year's exposure to any deregulatory proposal.

[c] Volume expiring totals do not add to the total gas flowing because of declining production in previous years under expiring contracts.

[d] Cumulative volume released includes cumulative volumes released in previous years plus amount flowing that year.

The following graph shows the cumulative gas volumes that will be released from regulation because of the expiring contracts and highlights the differences between constant production and declining production using the three production decline curves.

PROJECTED VOLUMES OF NATURAL GAS UNDER VARIOUS PRODUCTION CURVES FOR CONTRACTS EXPIRING DURING THE PERIOD 1975 TO 1985



[1] VOLUMES ARE CUMULATIVE

CHAPTER 3

INDEFINITE PRICING CLAUSES IN NATURAL GAS CONTRACTS

Indefinite pricing clauses included in many of the natural gas sales contracts between producers and interstate pipelines provide for future changes in the price of gas sold, depending on certain economic factors occurring. Some indefinite pricing clauses may have an effect on the amounts of gas that would be freed from price controls if deregulation legislation were enacted. Assuming this occurs, the amount of gas currently under contract which would be deregulated because of indefinite pricing clauses would depend on the provisions of the deregulating statute and/or FPC rulemaking actions.

A natural gas contract may contain one or more of the following indefinite pricing clauses.

--The renegotiation clause allows for price changes at some specific time.

--The redetermination clause is similar to the renegotiation clause in its effect and provides for price escalations to the fair-market price or some negotiated price that may be higher than the FPC-accepted price level.

--The favored-nation clause allows for increased rates if other contracts in the area specify higher rates.

--The deregulation clause permits higher rates if regulatory control is removed.

--The area rate clause allows prices to escalate to the future FPC-established rates for the area covered by the contract.

Of the above clauses, only the area rate clause appears to be permissible under FPC regulations.

AMOUNT OF GAS SUBJECT TO INDEFINITE PRICING CLAUSES

Data filed by producers pursuant to an August 17, 1973, FPC order showed that about 4.3 TCF, or 33 percent, of the gas was sold under long-term contracts subject to one or more of the impermissible indefinite pricing clauses. Further data breakdown showed that about 26 percent of the gas was sold under long-term contracts having renegotiation or redetermination clauses, 10 percent was under contracts having favored-nation clauses, and about 2 percent was under contracts having deregulation clauses. The above breakdown totals more than 33 percent because some contracts have more than one indefinite pricing clause.

Recent trends in long-term contracting by gas producers seem to be toward including deregulation clauses in contracts. Over half the long-term contracts filed with FPC in recent months contained such clauses, presumably anticipating some form of gas deregulation by the Congress.

Data filed by producers showed that about 3.9 TCF, or 30 percent, of gas was sold under contracts having the permissible area rate clauses.

EFFECT OF CLAUSES IF DEREGULATION OCCURS

Assuming natural gas deregulation occurs, the amount of gas currently under contract which would also be deregulated because of indefinite pricing clauses would depend on the provisions of the deregulating statute and/or FPC rulemaking actions.

FPC believes that legislation which removes price controls on new gas will not necessarily permit gas under existing contracts to be released from regulation because of indefinite pricing clauses. FPC regulations (18 CFR 154.93) make such clauses inoperative and of no effect at law. The regulations read, in part:

> "* * *Provided, That in contracts executed on or after April 3, 1961, for the sale or transportation of natural gas subject to the jurisdiction of the Commission, any provision for a change of price other than the following provisions shall be inoperative and of no effect at law; the permissible provisions for a change in price are:
>
> (a) Provisions that change a price in order to reimburse the seller for all or any part of the changes in production, severance, or gathering taxes levied upon the seller;
>
> (b) Provisions that change a price to a specific amount at a definite date;
>
> (b-1) Provisions that permit a change in price to the applicable just and reasonable area ceiling rate which has been, or which may be, prescribed by the Commission for the quality of the gas involved."

In addition, paragraph (c) of the regulations permit a price redetermination once every 5 years to an amount which is not higher than the FPC-accepted price level in effect for the same area at that time. Contracts can have either provision (b), above, or a paragraph (c) price redetermination provision, but not both.

The Supreme Court expressly upheld FPC's power to prohibit using indefinite pricing clauses in FPC v. Texaco, 377 U.S. 33 (1964).

CHAPTER 4

DEREGULATION STUDY DATA SHOULD BE RELIABLE AND CURRENT

The Natural Gas Act authorizes FPC to require natural gas companies under its jurisdiction to file periodic or special reports as it may prescribe necessary or appropriate to help it properly administer the act. The August 17, 1973, FPC order required producers to provide 1972 sales data under their contracts with interstate pipelines along with other information, including the date and term of the contracts.

FPC used sales volume data for a single year--1972--to project gas volumes under expiring contracts. The projections' reliability was questionable, however, since FPC did limited verification of the data to determine if it was complete and accurate. The FPC staff used, and the Congress will use, these projections of gas volumes to estimate the cost to consumers of gas that could be freed from price controls under deregulation legislation. Therefore, as long as the natural gas deregulation issue confronts the Congress and FPC, FPC should maintain current data so that it is readily available to the Congress and others for decisionmaking.

ACCURATE AND COMPLETE DATA NEEDED

The 1972 sales data obtained by the August 17, 1973, FPC order was obtained on a one-time only basis as part of a rulemaking procedure to establish just and reasonable rates for natural gas. This data was the only available basis for projecting the amount of gas that would be released from price controls if deregulation legislation were enacted. Therefore, reliable information was important.

To insure the projections' reliability, the base year data's accuracy and completeness must be verified. FPC did only limited verification of the data reported. We noted several differences in the 1972 sales data submitted by producers pursuant to the August 17, 1973, order and the 1972 sales data that they submitted on FPC Form 301-B, Independent Producers Report.

For example, the following schedule shows important differences in the data reported for five companies.

Company	1972 Natural gas sales August 17 order	 Form 301-B
	(BCF)	
A	454	278
B	697	780
C	15	232
D	27	15
E	9	30

FPC officials said that they were aware of some of the differences in reported sales volumes, but they could not explain such differences. In their opinion, the data obtained pursuant to the August 17 order was the most accurate data available. Without verification, however, we can see no basis for considering either set of data as being accurate and reliable.

We recognize that the total 1972 sales volume reported under the August 17 order differs by about 590 BCF, or only about 4 percent from the Form 301-B total. Total sales volumes, however, are inappropriate for making projections of gas volumes to be released under expiring contracts. The volumes should be analyzed on an individual producer basis since some producers could have relatively small percentages of their total sales volume expiring under contracts from 1975 to 1985, whereas other producers could have relatively large percentages expiring. Thus the data for each producer must be accurate and complete to ensure the reliability of the projections.

FPC officials stated that data collection and compilation took a year and 3 months because of (1) the large number of reports filed, (2) incorrect or incomplete data submitted by the producers, necessitating followup requests by FPC, and (3) some producers did not file the data promptly.

Nevertheless, the summary did not contain all required data for the following reasons.

--Four producers simply did not file the data requested. According to the Forms 301-B filed by these producers, they sold 108 BCF of gas in 1972. Although this amount is not great compared with the amount sold nationally by all producers selling to interstate pipelines, we believe FPC should not allow their requests to go unheeded and should actively pursue the data to make its report all inclusive. Certainly 1 year and 3 months gave FPC enough time to obtain the data from all companies.

--Many producers filed incomplete data. Of primary concern are those producers which did not provide contract dates and terms which were critical in determining the amount of gas that would be released from contract during certain periods. In such instances, FPC showed the contracts expiring prior to 1975. In all, about 218 BCF of gas were considered to have been released from contract before 1975 even though FPC did not know when it would be released. We could not determine how many of these contracts would expire during 1975-85, but many conceivably would, because a large number of these long-term contracts, usually 20 years, were entered into between 1955 and 1965.

CONCLUSIONS

Although gathering and compiling voluminous data on a one-time basis from many gas producers is difficult and time consuming (15 months), it is, nevertheless, important and should be approached aggressively and conscientiously. Important decisions may be based on the data obtained; it should, therefore, be as complete and reliable as possible.

Although we recognize that the data obtained by the FPC was primarily for establishing just and reasonable gas rates, it nevertheless became critical to the various deregulation studies on which important decisions may be based.

Considering the trend toward shorter term contracts and the inclusion of deregulation clauses, we believe that FPC must maintain current information so that needed data is readily available for use in future congressional and FPC decisionmaking.

RECOMMENDATION TO THE CHAIRMAN, FPC

While debates over natural gas deregulation continue before the Congress, we recommend that the Chairman, FPC, institute procedures aimed at keeping FPC apprised of the status of gas flowing under contracts subject to its jurisdiction. In doing so FPC should, to the extent possible, use (1) data regularly supplied, such as gas sales volumes data on Form 301 and (2) the data received pursuant to the August 17 order.

If available information is inadequate, FPC should consider requesting the additional data needed to form a base which could then be periodically updated.

In any case, however, FPC should institute procedures to independently verify, at least on a sample basis, that the data received is complete, accurate, and reliable.

AGENCY COMMENTS

In a July 10, 1975, letter, the Chairman, FPC expressed general agreement with our recommendation and described the actions that had been taken or were planned to implement it. (See app. III.)

The Chairman said that FPC recognized that the data received under the August 17, 1973, order had limitations with respect to its use in deregulation studies and that procedures were being developed to update and verify the data. He said that the FPC staff would incorporate the data into its Regulatory Information System at an appropriate time.

The Chairman said that the large volume of data filed with FPC dictates selective and limited verification within existing manpower and budget limitations. He explained that the usefulness of any increased level of reliability or accuracy, through intensified verification measures, must be balanced against the required increases in manpower and budget or the decrease in timelinesss of the data.

We believe that the actions being taken or planned by FPC, if done effectively and promptly, will provide FPC and the Congress with accurate and reliable data on gas under contracts subject to FPC jurisdiction, thereby enhancing the decision making process.

CHAPTER 5

SCOPE OF REVIEW

Our examination was conducted at FPC headquarters in Washington, D.C.

We reviewed FPC's records, policies, and procedures for collecting and reporting natural gas data. We also reviewed recent studies prepared by FPC and others relating to natural gas deregulation.

We discussed pertinent matters with agency officials.

United States Senate
WASHINGTON, D.C. 20510

December 4, 1974

B-178205

The Honorable Elmer B. Staats
Comptroller General of the
United States
Washington, D. C. 20548

Dear Mr. Staats:

Congress is now considering proposals to deregulate "new" natural gas, meaning that gas which is not now flowing under contract for interstate sale. This proposal would repeal provisions of present Federal law that grant the Federal Power Commission regulatory authority over the field prices of natural gas.

Under the principal deregulation proposal now being advanced, the so-called Buckley Amendment, even that natural gas that is presently flowing under contract would be reclassified as "new" gas and thereby freed from price controls upon expiration of the primary term of such contracts. The result would apparently be a several-fold increase in the price of such flowing gas, without any compensating benefits to consumers in the form of enhanced supplies.

We would be reluctant to support legislation at this time that would result in significantly higher consumer prices without compelling evidence that its benefits justify its costs. It is imperative that Congress and the public know just what the likely cost of this proposal to American consumers will be. A confident estimate of the cost of deregulating "new" natural gas (including gas released at the expiration of existing contracts) can only be made with the aid of an audit of the contracts for natural gas that are now subject to Federal Power Commission price jurisdiction.

Accordingly, with this letter, we are requesting that the General Accounting Office investigate the terms of present inter- and intrastate natural gas field sale contracts. The audit would have as its objective a determination of the volume of flowing gas whose prices could be expected to be released from price regulation, annually and cumulatively, for the years 1975 through 1985. It would cover, among other things, an accounting of --

(a) How much gas is currently flowing under contract in the interstate market?

(b) Taking into account the natural decline in production in individual fields, how much gas is expected to be produced under these contracts or (where contracts are scheduled to expire) those properties now subject to such contracts in each year, 1975 through 1985?

(c) When will these contracts expire; that is, how much production is covered by contracts whose primary term expires each year? Taking into account both the natural decline in production and the expiration of contracts, how much gas can be expected to be produced (1) subject to existing contracts, and (2) free from the control of such contracts, from properties now dedicated to interstate commerce, in each year?

(d) How many contracts have provisions for renegotiation at new higher rates; how much production is covered by such contracts? Here again, we would like an estimate of the volume of gas expected to be produced each year from properties subject to such renegotiable rates?

A similar review, to the extent possible, of natural gas sold in the producing states ("intrastate" gas) would also be helpful since deregulation of interstate gas sales will result in higher interstate prices, which will in turn tend to pull up at least some intrastate gas prices. This review should examine the volume of intrastate natural gas sold, along with the kinds of contractual controls on the price of such gas that would be subject to likely price increases by virtue of renegotiation clauses or contract expiration in each year, 1975 to 1985.

It should be noted that a Federal Power Commission staff study shows that 1.6 trillion cubic feet (annual rate) of natural gas would be released from control of current interstate contracts in 1975. On the basis of this estimate and a rather conservative assumption regarding the increase in "new" gas prices under deregulation, an FPC official estimated that release of new natural gas from price control would cost consumers a cumulative $60 billion through 1980. A similar estimate was made in an economic impact report recently prepared for us by the Economics Division of the Congressional Research Service.

The foregoing estimates may in fact be conservative, because, among other things, they do not include an estimate for higher prices of gas sold in the producing states ("intrastate" gas), resulting from the additional competition by interstate buyers who would be able, under deregulation, to bid what the market will bear for gas newly released from contract. In any event, it is imperative that Congress, before it acts on any deregulation proposal, have a credible projection of the volumes of gas that they would actually free from controls.

As energy costs and supplies, and their impact upon the Nation's economy, will be major Congressional concerns, not only during the remaining weeks of the 93rd Congress but throughout at least the first months of the 94th Congress, we would appreciate if possible your office placing this audit and review request in a priority position.

Sincerely yours,

Henry M. Jackson

Henry M. Jackson
U.S. Senate

John E. Moss

John E. Moss
U.S. House of
Representatives

JOHN E. MOSS
3RD DISTRICT
SACRAMENTO, CALIFORNIA

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CONGRESS OF THE UNITED STATES
HOUSE OF REPRESENTATIVES
WASHINGTON, D.C. 20515

GOVERNMENT OPERATIONS COMMITTEE:
RANKING MAJORITY MEMBER SUBCOMMITTEES ON
FOREIGN OPERATIONS & GOVERNMENT INFORMATION
CONSERVATION & NATURAL RESOURCES

INTERSTATE AND FOREIGN COMMERCE COMMITTEE:
CHAIRMAN,
COMMERCE & FINANCE SUBCOMMITTEE

DEMOCRATIC STEERING AND POLICY COMMITTEE

February 21, 1975

Mr. Henry Eschwege
Director
Resources and Economic
  Development Division
U.S. General Accounting Office
Washington, D.C. 20548

Dear Mr. Eschwege:

This is to confirm receipt of your February 7, 1975, letter as well as to outline four elements which we view as essential in the investigation of present interstate and intrastate natural gas contracts for purposes of determining the cost deregulating "new" natural gas we have requested. They are as follows:

(1) Provide figures for the volume of gas to be released under expiring contracts for each of the years 1975 through 1985 and cumulatively, unadjusted for production decline.

(2) Provide additional sets of figures for (1) above but with adjustments for production decline according to the various formulas now in use along with some explanation of the background and merits of each of the formulas used with possibly some indication as to which is the most reliable formula, and in turn, the most reliable set of figures.

(3) Provide comments about why certain information was not available, if that is the case, including evaluation of the auditing standards as well as the accounting and retrieving systems used by the Federal Power Commission including mention of those that they might better be using (if that is the case) in order to properly meet its regulatory responsibilities.

(4) Provide figures for the amount controled by contracts which have renegotiation clauses and which could, if "new" gas is deregulated, be renegotiated at the new, presumably higher rates.

Your letter indicated that the Federal Power Commission staff estimates that it would take an inordinate amount of time to gather this information. It is, however, an important aspect of this investigation. Accordingly, a sampling of various types of renegotiation clauses with an evaluation and some estimate of their prevalence in natural gas contracts is suggested as an alternative.

We appreciate the attention you have given to these matters and trust you will continue working closely with our staff on this assignment.

Sincerely,

Henry M. Jackson
U.S. Senate

John E. Moss
U.S. House of
Representatives

FEDERAL POWER COMMISSION
WASHINGTON, D. C. 20426

OFFICE OF THE CHAIRMAN

JUL 10 1975

Mr. Henry Eschwege
Director
Resources and Economic
Development Division
U. S. General Accounting Office
441 G Street, N.W.
Washington, D. C. 20548

Dear Mr. Eschwege:

This is in response to your request of June 27, 1975, for my review and comment on your draft report entitled "Selected Contract Sales Information Related to the Deregulation of Natural Gas." In addition to the general analysis below, I have attached a list of specific suggested revisions to your report. (Attachment 1)

Your report is in response to the request of December 4, 1974, by Senator Henry M. Jackson and Congressman John E. Moss for certain data regarding the amount of flowing natural gas which would become deregulated upon expiration of existing contracts if deregulation legislation were enacted similar to the so-called Buckley Amendment (new gas and gas from expiring contracts). Several of these "roll-over" studies have been done as of that time by BNG Staff as part of other overall price and deregulation impact studies. 1/ These roll-over

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1/ "A Preliminary Evaluation of the Cost of Natural Gas Deregulation," January, 1975; "Analysis of the Economic Impact of FPC Opinion No. 699-H on Producers," December 13, 1974; "Opinion No. 699-H," Appendices A and B to Commissioner Smith's partial dissent, December 4, 1974.

studies were based on data gathered in the R-478 proceeding which at the time the studies were made had not been completely compiled. However, this was the only readily available source of the data needed to make these roll-over studies in a timely fashion.

Docket No. R-478 was instituted by Notice issued May 23, 1973 to prescribe a Nationwide Rulemaking To Establish Just and Reasonable Rates For Natural Gas Produced From Wells Commenced Before January 1, 1973. By Order issued August 17, 1973, large producers, pipeline affiliates and pipelines with off-system sales were ordered to complete, verify, and file with the Commission the six data collection schedules which were attached to the August 17, 1973 Order. The data was requested to furnish the Commission and parties to the proceeding with cost, revenue, and volume information for the year 1972 to be used in establishing the rate in R-478.

FPC Staff reconciled and summarized the data on Schedules 1 through 4-A which pertained to production expenses, exploration and development costs, etc., and sent the summary to all parties to the proceeding on November 13, 1974. Schedule 5, which is designated as FPC Form 459, is an analysis of the producer rate schedules, and was designed to capture such information as contract date, contract term, indefinite pricing conditions, effective prices and future price escalation provisions. Schedule 5 was to be submitted on November 9, 1973, but because of the time required to complete the schedule, most producers were granted extensions of time.

Roughly 8,300 rate schedule analyses were submitted to the FPC. Staff reviewed the data, made corrections where necessary (a summary of all the corrections made by staff was sent to the filing parties), and where staff found discrepancies which staff could not resolve, or found that certain data fields were not completed, Staff sent a letter to the filing party requesting further information. The data was then keypunched and verified for keypunch accuracy and copied onto magnetic tape.

The magnetic tape containing the Schedule 5 data was made available to the public on March 4, 1975.

The GAO report questioned the prudence of using such incomplete and unverified data in making important studies of the volumes of gas that could be freed from price controls under deregulation legislation.

The FPC staff was well aware of the limitations of the R-478 data and, in fact, the overall conclusion of the FPC Deregulation Task Force study was that ". . . . a conclusive determination and quantification of these impacts (deregulation) has not as yet been determined." The report continued, "While the analytical framework established by the task force is reasonable for preliminary evaluation, the illustrative results which it shows are dependent on the reliability of the input data." The task force recommended further study of the impact of deregulation.

Further, on January 21, 1975, a BNG memorandum dated January 16, 1975, (Attachment 2) was submitted to GAO staff at a meeting in my office. The memorandum discusses the Deregulation Task Force roll-over study and was prepared expressly to assist GAO in their investigation. That memorandum characterizes the R-478 data as "preliminary and incomplete." Thus, it is unlikely that this study will be viewed as final and conclusive in making important decisions on deregulation either by Congress or the FPC, as implied by the GAO report.

The GAO report recommends that the FPC institute procedures aimed at keeping the FPC apprised of the status of gas flowing under contracts subject to its jurisdiction, utilizing to the extent possible (1) data regularly supplied, such as gas sales volumes on Form 301, and (2) the data received pursuant to the August 17, 1973 order relating to flowing gas. FPC's Bureau of Natural Gas has recognized this need for some time and has been developing procedures to obtain this type of data.

The data processing system now being developed at the FPC uses an on-line system for rapid retrieval of data from a computer stored data base. FPC public use forms including Forms 459 and 301-B have been redesigned for rapid data capture. The new design reduces a tedious task of hand-coding the forms, which takes several months, to direct processing by optical character reader or keypunch in a matter of weeks.

Data elements from the public use forms have been structured into two files; a producer file and a pipeline company file. Forms 301-B and 459 have been included in the design of these computer files. One of the basic goals of the forms redesign and the computer file design is the elimination of duplication of reported data. To achieve this goal the FPC staff has proposed a two step approach with regard to the Forms 301-B and 459.

First, staff proposes that the newly designed Form 459 be filed on a one-time basis by the producers to bring the data base to a current state. Form 301-B would also be filed. Comparisons between volumes of sales and revenues under the same rate schedule reported on both forms can be readily made by computer checks and followed up with the companies affected where required.

Subsequently whenever a certificate application is filed for a new sale a complete Form 459 would be filed. For a contract amendment adding acreage or changing other contract terms, a partial Form 459 would be filed to reflect the change. It is anticipated that yearly volumes and revenues would be reported only on Form 301-B.

Such a project will require a significant amount of time to complete. Since the R-478 data, most notably Schedule 5, (FPC Form 459) is the most comprehensive data pertaining to large producer contracts and is readily accessible through computer programs, it is anticipated that further interest in this data will be forthcoming in the near future. However, the test year for R-478 was 1972 and the data is now more than two years old. Since 1972, contract terms have expired, properties have been abandoned, added, and reassigned, and the list of large producers has changed. But of primary concern is that area ceilings, production, taxes, contract rates and sales volumes have changed. In view of the foregoing, FPC staff will develop procedures for updating the R-478 data and for incorporating it in the RIS data system at an appropriate time in the future. The ideal situation would be to have such information available for all large producer sales rather than just R-478 sales, and to have such data filed on a continuing basis.

FPC staff will also consider modification of FPC Form 301-B to obtain the data necessary for a roll-over study. A seemingly minor modification to add contract dates to Form 301-B would suffice. However, producer contract data filed on FPC Form 459 is much more comprehensive and since this data will prove useful in other studies, such as revenue impact studies of area rate ceilings and contract rate tracking, it may be most desirable to utilize the Form 459 in any updating procedures.

With regard to verification of data filed with the FPC, it must be recognized that the sheer volume of data filed dictates selective and limited verification within existing manpower and budget limitations. The usefulness of any increased level of reliability or accuracy, through intensified verification measures, must be balanced against the required increases in manpower and budget or the decrease in timeliness of the data.

At page 1 of the report it is asserted that "At one end of the network are more than 3,000 producers, consisting of large petroleum companies and small independent producers, most of whose total production is sold in interstate commerce." I believe this statement requires revision in the following respects: (1) There are more than 7,000 jurisdictional producers, and (2) I do not believe the small independent producer would sell "most" of their total production in interstate commerce. The contrary is probably true since these producers, particularly in the Southwest have large intrastate markets with insatiable demand for natural gas.

Sincerely,

John N. Nassikas

John N. Nassikas
Chairman

Enclosures [See GAO note.]
1. Comments and Revisions
2. BNG Memo Jan. 16, 1975
3. Letter 3/25/75 to
   Mr. Gerald Elsken

GAO note: This material is not included in this report.

STATEMENT OF JACK M. ALLEN
CHAIRMAN, NATURAL GAS COMMITTEE
INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

TO THE
ENERGY AND POWER SUBCOMMITTEE
HOUSE INTERSTATE AND FOREIGN COMMERCE COMMITTEE
JANUARY 26, 1976

My name is Jack M. Allen. I am President of Alpar Resources, Inc., Perryton, Texas, an independent producer of oil and natural gas. I am chairman of the Natural Gas Committee of the Independent Petroleum Association of America (IPAA), a national trade association of some 4,000 oil and natural gas producers representing all producing areas of the United States. I am appearing on behalf of IPAA today.

We appreciate this opportunity to present our views with respect to some of the questions in which this committee has expressed an interest. Before getting to these specifics, I would like to discuss briefly the significant role of independent producers in providing the consuming public with natural gas supplies. In much of the public and political debate on the issue of natural gas deregulation, Mr. Chairman, the emphasis of deregulation critics invariably is on what they see as the dominance of the large oil companies in natural gas production, which leads such critics to the erroneous conclusion that the gas producing industry is an anti-competitive monopoly.

Any objective study of the structure of the industry--whether from the Federal Trade Commission which has been an industry critic or the latest study by George Washington University--has concluded

THAT COMPARED WITH MOST MAJOR U.S. INDUSTRIES, THE PRODUCTION OF NATURAL GAS IS AN INDUSTRY CHARACTERIZED BY EFFECTIVE COMPETITION.

IT IS TRUE THAT CONTROL OF PRODUCTION IS SOMEWHAT MORE CONCENTRATED THAN WAS FORMERLY THE CASE. I SUBMIT, HOWEVER, THAT SUCH CONCENTRATION AS HAS OCCURRED HAS COME ABOUT DURING THE PERIOD OF FEDERAL REGULATION. TODAY, THERE ARE LESS THAN HALF AS MANY INDEPENDENT EXPLORER-PRODUCERS SEARCHING FOR AND PRODUCING PETROLEUM FUELS (CRUDE OIL AND NATURAL GAS) AS THERE WERE IN THE MID-1950'S WHEN, UNDER THE MANDATE OF THE SUPREME COURT, THE FEDERAL POWER COMMISSION ASSUMED JURISDICTION OF WELLHEAD NATURAL GAS PRICES.

UNDER THE GENERALLY-ACCEPTED SENSE OF THE TERM, "MONOPOLY" IS PROMOTED WHEN LARGE ENTITIES IN A GIVEN FIELD HAVE SUCH MARKET DOMINANCE THAT THEY CAN REDUCE PRICES BELOW THE COSTS OF SMALLER COMPETITORS, THUS FORCING OUT COMPETITION. MANY SMALL COMPETITORS IN THE NATURAL GAS PRODUCING INDUSTRY HAVE GIVEN UP AND QUIT IN THE PAST TWO DECADES, BUT THEY DID SO NOT BECAUSE OF THE DOMINANCE OF THE "MAJOR OIL COMPANIES," BUT BECAUSE THE FEDERAL GOVERNMENT HELD THEIR PRICES SO LOW THAT THE PROSPECTIVE PROFITS NO LONGER JUSTIFIED THE RISK OF OIL AND NATURAL GAS EXPLORATION. ALL DURING THIS PERIOD, THE PRODUCERS, BOTH LARGE AND SMALL, WERE APPEALING FOR ACTION TO INCREASE WELLHEAD PRICES.

IN THE 1960'S, A DECADE IN WHICH THE REAL (CONSTANT DOLLAR) PRICES OF DOMESTIC OIL AND NATURAL GAS DECLINED CONSTANTLY WHILE THE ECONOMY GENERALLY WAS EXPERIENCING INFLATION, THOUSANDS OF INDEPENDENT EXPLORER-PRODUCERS SOLD OUT AND GOT OUT OF THE INDUSTRY. THIS WAS A PERIOD OF GREAT CONTRACTION IN THE INDUSTRY. THOSE WHO

SOLD THEIR OIL AND GAS PRODUCING PROPERTIES PUT THEIR RESOURCES INTO REAL ESTATE, CONSTRUCTION, MOTELS, SHOPPING CENTERS, AND BOWLING ALLEYS--ALL OF WHICH WERE FAR MORE ATTRACTIVE INVESTMENTS.

I FIND IT IRONIC, MR. CHAIRMAN, THAT THOSE WHO ARE SUCH STAUNCH CHAMPIONS OF FEDERAL PRICE REGIMENTATION BECAUSE THEY BELIEVE THE NATURAL GAS PRODUCING INDUSTRY IS TOO CONCENTRATED ARE ARGUING FOR CONTINUANCE OF THE SYSTEM THAT CAUSED MOST OF THE CONCENTRATION.

DESPITE THE CONTRACTION IN THE INDUSTRY CAUSED BY MISGUIDED FEDERAL PRICE CONTROLS, THE REMAINING INDEPENDENT PRODUCERS HAVE CONTINUED TO PLAY A SIGNIFICANT ROLE IN FINDING AND PRODUCING NATURAL GAS--ALBEIT THAT NOT ENOUGH HAS BEEN FOUND AND PRODUCED. I WOULD REFER THE COMMITTEE TO AN ANALYSIS, BY THE AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS, OF OIL AND NATURAL GAS DISCOVERIES WHICH RESULTED FROM WILDCAT DRILLING IN THE YEARS 1969-73.

THE AAPG CLASSIFIED AS "SIGNIFICANT" THE NATURAL GAS DISCOVERIES WHICH FOUND SIX BILLION OR MORE CUBIC FEET OF NATURAL GAS. DURING THE FIVE-YEAR PERIOD, THE UNITED STATES HAD 315 SIGNIFICANT NATURAL GAS DISCOVERIES OF WHICH INDEPENDENT PRODUCERS ACCOUNTED FOR 242 OR 77 PERCENT. MAJOR COMPANIES HAD 73 OF THESE DISCOVERIES. INDEPENDENT PRODUCERS, IN THEIR DISCOVERIES, FOUND 62.5 PERCENT OF THE NATURAL GAS RESERVES ATTRIBUTED TO ALL SIGNIFICANT U.S. DISCOVERIES IN THESE FIVE YEARS.

WHILE INDEPENDENT PRODUCERS FOUND MOST OF THE NATURAL GAS, THEY ACCOUNTED FOR ONLY 43.8 PERCENT OF THE "SIGNIFICANT" OIL DISCOVERIES. THUS OF TOTAL PETROLEUM HYDROCARBONS, THE MAJOR OIL

COMPANIES AND THE INDEPENDENTS CONTRIBUTED ABOUT EQUALLY TO THE DISCOVERY AND DEVELOPMENT OF DOMESTIC PETROLEUM RESOURCES IN THE FIVE YEARS COVERED BY THE AAPG STUDY.

I DO NOT POINT THIS OUT TO DETRACT FROM THE CONTRIBUTIONS OF THE LARGER COMPANIES IN THE INDUSTRY, BUT TO MAKE THE POINT THAT THE APPROXIMATELY 10,000 INDEPENDENT EXPLORER-PRODUCERS ARE A VITAL FORCE IN THE HIGHLY COMPETITIVE ACTIVITY OF EXPLORING FOR AND PRODUCING OIL AND NATURAL GAS IN THE UNITED STATES. I WOULD REITERATE MY BELIEF THAT INDEPENDENTS WOULD BE MORE NUMEROUS AND BE MAKING AN EVEN MORE SIGNIFICANT CONTRIBUTION TO THE DEVELOPMENT OF SECURE DOMESTIC ENERGY SUPPLIES--EXCEPT FOR THE UNREALISTIC FEDERAL PRICE REGULATION IMPOSED ON WELLHEAD NATURAL GAS PRICES IN THE PAST TWO DECADES.

NOW, MR. CHAIRMAN, I WOULD LIKE TO TURN TO SOME OF THE SPECIFICS OF SOME OF THE PENDING PROPOSALS, BEGINNING WITH THE ISSUE OF DEFINING "NEW" NATURAL GAS.

I. DEFINITION OF NEW GAS

IT IS URGENT THAT ANY NATURAL GAS LEGISLATION INCLUDE A DEFINITION OF "NEW" GAS BROAD ENOUGH TO ENCOMPASS THE DRILLING OF NEW WELLS IN EXISTING FIELDS AND RESERVOIRS. OTHERWISE, MUCH NATURAL GAS THAT COULD THEN BE AVAILABLE IN A RELATIVELY SHORT TIME TO INTERSTATE PIPELINES WILL SIMPLY NOT BE AVAILABLE FOR YEARS, IF EVER.

THE PANHANDLE-HUGOTON GAS FIELD, WHICH EXTENDS FROM SOUTHWEST KANSAS THROUGH THE PANHANDLE OF OKLAHOMA AND INTO THE NORTHEAST PANHANDLE OF TEXAS IS THE WORLD'S LARGEST GAS FIELD. IT PRODUCES

MORE THAN ONE TRILLION CUBIC FEET OF NATURAL GAS ANNUALLY. MOST OF THE PRODUCERS IN THE FIELD ARE RECEIVING 10¢ TO 13¢ PER MCF FOR THEIR GAS. THE FIELD WAS DEVELOPED ON 640 ACRE SPACING, THAT IS, ONLY ONE WELL FOR EACH 640 ACRE SECTION OF LAND. MANY PRODUCERS ARE OF THE OPINION THAT 1/2 BILLION CF DAILY AND MANY ADDITIONAL TRILLIONS OF CUBIC FEET OF GAS ULTIMATELY COULD BE RECOVERED IF THE FIELD WERE REDRILLED ON 320 ACRE SPACING. IF THE DEFINITION OF NEW GAS PRECLUDES DRILLING NEW WELLS IN AN EXISTING FIELD OR RESERVOIR, AS A MATTER OF ECONOMICS, THE FIELD WILL NEVER BE FURTHER DEVELOPED. IF, HOWEVER, THE DEFINITION OF NEW GAS PERMITTED OPERATORS TO NEGOTIATE NEW PRICES FOR WELLS DRILLED AFTER JANUARY 1, 1975, A CONCERTED, COOPERATIVE EFFORT COULD BE MADE WHICH COULD RESULT IN MANY ADDITIONAL TRILLIONS OF CUBIC FEET OF NATURAL GAS BEING MADE AVAILABLE TO THE INTERSTATE MARKET. PRODUCERS WOULD FIRST HAVE TO OBTAIN PERMISSION FROM THE APPROPRIATE STATE AUTHORITIES TO CHANGE THE SPACING TO 320 ACRES. THEN THEY COULD NEGOTIATE NEW CONTRACT PRICES AND DRILL ADDITIONAL IN-FIELD WELLS. THEY CANNOT AFFORD THE EXPENSE OF NEW WELLS AND COMPRESSION EQUIPMENT AT EXISTING OR FPC PERMITTED PRICES.

THERE ARE OTHER EXAMPLES WHY THE DEFINITION OF NEW GAS SHOULD APPLY TO NEW WELLS DRILLED IN EXISTING FIELDS. THERE ARE LEASES HELD BY PRODUCTION IN DEEP FIELDS BELOW 10,000 FEET WHICH COULD BE IN-FIELD DRILLED ON SMALLER SPACING PATTERNS IF PRICE JUSTIFIED THE EXPENSE. AFTER SUSTAINED PRODUCTION, WE SOMETIMES LEARN THAT ONE WELL WILL NOT DRAIN 640 ACRES, WHICH IS THE SPACING ON WHICH WE NORMALLY DRILL GAS WELLS. IN MANY FIELDS, WE COULD GO

TO 320 ACRE SPACING, AND IN SOME, 160 ACRE SPACING, BUT THE CURRENT COST OF DRILLING HAS INCREASED TO THE EXTENT THAT IT WOULD NOT BE ECONOMICALLY FEASIBLE TO DO SO. IF PRODUCERS WERE PERMITTED A NEW COMPETITIVE PRICE FOR IN-FIELD WELLS DRILLED WITHIN THE FIELD, NEW DRILLING PROGRAMS COULD COMMENCE WHICH WOULD MAKE SEVERAL BILLION CUBIC FEET OF GAS PER DAY AVAILABLE TO INTERSTATE PIPELINES TO WHICH IT IS NOW DEDICATED. IN MANY SUCH FIELDS, PRODUCERS SELLING TO INTRASTATE LINES WITH BETTER PRICES HAVE ALREADY IN-FIELD DRILLED, WHILE PRODUCERS DEDICATED TO INTERSTATE LINES CANNOT AFFORD TO DO SO.

AS A MATTER OF ECONOMIC NECESSITY, SUCH DRILLING WILL BE POSTPONED UNTIL THIS OR SOME FUTURE CONGRESS DECONTROLS PRICES, AND THE MARKET STRUCTURE MAKES THE DRILLING OF THESE IN-FIELD WELLS ECONOMICALLY FEASIBLE. SUCH IN-FIELD DRILLING IS PROBABLY THE QUICKEST WAY TO PUT MEANINGFUL, ADDITIONAL GAS SUPPLIES INTO INTERSTATE PIPELINES WHERE IT'S BADLY NEEDED, AND WILL BE EVEN MORE NEEDED IN THE FORESEEABLE FUTURE.

MUCH OF THE NATURAL GAS REMAINING TO BE DISCOVERED, IF NOT MOST OF IT, IS AT DEPTHS BELOW 15,000 FEET, AND IN SOME CASES, AS DEEP AS 25,000 FEET. WELLS TO THESE DEPTHS ARE VERY EXPENSIVE, RANGING UPWARD FROM $1.5 MILLION FOR A DRY HOLE, AND $2 MILLION FOR A COMPLETED WELL. MANY COST $5 MILLION OR MORE. SUCH WELLS CANNOT BE DRILLED WITH THE EXISTING INTERSTATE PRICE STRUCTURE. AS THE INTRASTATE MARKET IS SATISFIED AND THE DEMAND MET, DEVELOPMENT OF THIS DEEP GAS WILL ABATE PENDING PROPER ECONOMIC INCENTIVES TO TAKE THE NECESSARY RISKS TO BRING THIS GAS ON STREAM. AS INTRASTATE DEMAND

IS MET, MANY OF THE REMAINING LOCATIONS WILL BE IN EXISTING RESERVOIRS AND FIELDS, AND IF THE DEFINITION OF NEW GAS EXCLUDES GAS IN "EXISTING DISCOVERED RESERVOIRS", OR "EXISTING FIELDS", PRODUCERS WILL NOT BE ABLE TO GENERATE THE INVESTMENT CAPITAL TO DEVELOP THESE FIELDS TO FULL POTENTIAL. THUS THE INTERSTATE MARKET WILL BE DEPRIVED OF GAS IT COULD OBTAIN BUT FOR A SHORT-SIGHTED DEFINITION OF NEW GAS.

FOR THESE REASONS, IT IS VERY IMPORTANT THAT ANY DEFINITION OF NEW GAS NOT BE SO RESTRICTIVE AS TO PRECLUDE NEW DEVELOPMENT WELLS IN EXISTING RESERVOIRS AND FIELDS.

II. CONTRACT PROVISIONS BETWEEN PRODUCERS AND PIPELINES RELATIVE TO RENEGOTIATION

SINCE 1971, MANY CONTRACTS BETWEEN PRODUCERS AND PIPELINES PROVIDE THAT IN THE EVENT THE PRICE OF NATURAL GAS IS DECONTROLLED, THE CONTRACT PRICE FOR THE GAS WILL BE RENEGOTIATED. THIS CONTRACT PROVISION WAS INCLUDED BECAUSE PRODUCERS FELT THAT CONGRESS INEVITABLY WOULD DECONTROL WELLHEAD PRICES IN RECOGNITION THAT (1) THIS SUPERIOR ENERGY FORM WAS SELLING AT PRICES BELOW ALL COMPETITIVE BUT INFERIOR FUELS, AND (2) A PRECIOUS NATURAL RESOURCE WAS BEING SQUANDERED FOR SUCH THINGS AS BOILER FUEL BECAUSE OF ARTIFICIALLY LOW, CONTROLLED PRICES. BASED ON THIS RENEGOTIATION PROVISION, MANY NATURAL GAS WELLS WERE DRILLED AT MARGINAL RATES OF RETURN IN ANTICIPATION THAT CONGRESS WOULD ACT TO PERMIT COMPETITIVE PRICES DURING THE LIFE OF THE WELLS.

If new gas legislation contains provisions permitting renegotiation, many contracts will be renegotiated, thereby increasing the price of gas as producers rightfully anticipated, I believe, when the wells were drilled. Inasmuch as the bulk of the cost of gas to most consumers is for transportation and distribution, the impact would not be severe. The benefit to consumers would be immediate as the additional cash flow would permit producers to begin to drill many additional wells, thereby increasing the supply available to the interstate market. Tremendous amounts of high risk capital will be required in the next few years to drill new wells necessary to attempt to meet the interstate demand for natural gas. Improved intrastate prices have demonstrated that the wells will be drilled if the price incentive is proper. Competitive interstate prices for natural gas would result in the same type of drilling campaigns to place gas in interstate lines.

I should say parenthetically, Mr. Chairman, that I am appalled at the charge made over and over by some of our so-called "consumer advocates" that natural gas producers are purposely "withholding" natural gas in anticipation of decontrol. Once a well is completed, producers need all the cash flow they can obtain. Production rates are regulated by state agencies. Royalty owners and investors would resort to legal action if producers deliberately withheld production or underproduced a well.

There has been a great deal of misunderstanding--and some deliberate distortion--of natural gas deliverability as treated in a producer-pipeline sales contract. No gas well can produce at a constant rate over its lifetime. To the contrary, all gas fields produce at a declining rate. The average wellhead sales contract, therefore, guarantees deliverability at an optimum rate agreed upon by seller and buyer, with an understanding that actual deliveries may--depending on many factors--vary above or below the agreed-upon rate over time. Contract provisions recognize that over time the deliverability will fall below the initial delivery rate until the production reaches zero, and the wells are abandoned.

The charge that producers deliberately produce wells below contract rates, in order to obtain higher prices in the future, simply is not correct.

III. THE IMPACT OF ROLLING OVER EXISTING CONTRACTS AT NEW GAS PRICES

Many older existing contracts for natural gas are in the 13¢ to 17¢ per MCF range and do not permit renegotiation under any circumstances during the life of the contract. Renegotiation provisions in the event of price decontrol (new legislation permitting) are included in many recent interstate contracts. All contracts for delivery of natural gas are for long term (usually 20 years) in order that the pipeline can justify building the line by borrowing on committed gas reserves. However, at the end of the contract term, there can be no logical argument that the producer and royalty owner should not receive the market price for the commodity--in this case, NATURAL GAS--FOR THE NEW, ENSUING TERM. THERE WILL, OF COURSE, BE AN IMPACT ON CONSUMERS AND USERS OF NATURAL GAS. THIS WOULD BE OVER A RELATIVELY LONG PERIOD OF TIME AS EXISTING CONTRACTS WILL EXPIRE OVER APPROXIMATELY 20 YEARS IN STAGGERED TERMS. THE RESULTING PRICE INCREASE WOULD BE ROLLED IN GRADUALLY. THE NEW PRICES WOULD PERMIT PRODUCERS TO INCREASE EXPLORATION AND DRILLING TO PRODUCE GREATER SUPPLIES OF NATURAL GAS IN INTERSTATE COMMERCE, AND THE LONG RANGE IMPACT ON THE CONSUMER WOULD BE BENEFICIAL.

IV. IMPACT OF INCREASED NATURAL GAS PRICES ON CONSUMERS

WE HEAR MUCH ABOUT THE IMPACT OF INCREASED NATURAL GAS PRICES ON CONSUMERS, PARTICULARLY RETIRED PERSONS AND THE POOR. THOSE ON FIXED INCOMES HAVE MORE TO LOSE BY THE PRESENT POLICIES, WHICH BRING ON GAS SHORTAGES AND ULTIMATELY FORCE THEM TO PAY MUCH HIGHER PRICES FOR ALTERNATE FUELS SUCH AS IMPORTED LNG AND SYNTHETIC NATURAL GAS.

WHEN THE COST OF CLOTHING GOES UP, OR THE COST OF FOOD GOES UP, OR THE COST OF SHELTER GOES UP, WE HAVE LEARNED NOT TO ENACT LEGISLATION FREEZING THE PRICE OF CLOTHING, FOOD, OR SHELTER, THEREBY CREATING SHORTAGES BY MAKING THE PRODUCTION OF CLOTHING, FOOD, OR SHELTER UNECONOMIC. THE SAME LOGIC APPLIES TO NATURAL GAS. WE CANNOT PUT A LID ON THE PRICE AND LEAVE THE COST OF FINDING NATURAL GAS UNCONTROLLED AND EXPECT TO FIND SUFFICIENT NEW SUPPLIES OF NATURAL GAS.

V. FEDERAL POWER COMMISSION REGULATIONS BURDENSOME

In the past few years, many producers have sold gas in interstate commerce for the first time. These producers are now becoming familiar with the bureaucracy known as the Federal Power Commission. They are subject to keeping records, filling in forms, and filing reports to an extent never dreamed possible. They daily receive directives and orders from the FPC. Few producers possess staffs of attorneys, accountants, and engineers necessary to analyze reports and complete the forms and do the reserve studies required by the Federal Power Commission. Most do not keep records in the manner or detail that makes information elicited by the FPC readily available, if available at all. This is a luxury they simply cannot afford.

In the case of my small company, which sells gas from about 20 wells in interstate commerce, our greatest volume of mail is from the FPC. The amount of time required to attempt to digest and comply with FPC matters is staggering. We are now involved in a hearing wherein we are required to appear and participate simply because over a period of some three years, we have collected less than $10.00 in excess of the presently permitted FPC small producer rate of 130% of the nationwide rate. We are expected to present volumes of information to explain and justify the overcharge. This is ridiculous.

Most producers I have visited--and this includes several hundred--are finding that selling new gas in interstate commerce

SUBJECT TO FPC JURISDICTION, DIRECTIVES AND ORDERS BECOMES MORE BURDENSOME EACH YEAR. THIS PROBLEM CAN BE REMEDIED BY DECONTROLLING THE PRICE OF NEW GAS AND TO THE EXTENT POSSIBLE FREEING PRODUCERS FROM THE UNBELIEVABLE RED TAPE ENCOUNTERED IN SELLING NATURAL GAS IN INTERSTATE COMMERCE.

NO ONE CAN DENY THAT PRODUCTION AND THEREFORE THE SUPPLY OF NATURAL GAS FOR CONSUMPTION HAS BEEN INCREASINGLY INADEQUATE TO MEET DEMAND SINCE 1968. IF CONGRESS DOES NOT TAKE CORRECTIVE ACTION TO PERMIT THE MARKET TO ACT TO ARREST THIS TREND, THEN IT IS INEVITABLE THAT (1) INCREASED DEMANDS FOR GAS MUST BE MET BY SYNTHETIC AND MANUFACTURED SUBSTITUTES COSTING SIX TO 10 TIMES THE PRESENT WELLHEAD PRICE OF NATURAL GAS SOLD IN INTERSTATE COMMERCE, AND (2) ULTIMATELY, PRESENT RESIDENTIAL CONSUMERS WILL BE FORCED TO FALL BACK ON THESE COSTLY SUBSTITUTES AS THE SUPPLY CONTINUES TO DWINDLE.

THE EXPERIENCE WE HAVE BEEN THROUGH WITH NATURAL GAS IS A PRIME EXAMPLE OF A BASIC TRUTH, WHICH IS: GOVERNMENT CAN CONTROL THE PRICE OF A BASIC COMMODITY, BUT IT CANNOT FORCE ANYONE TO INCREASE THE SUPPLY OF THAT COMMODITY AT COSTS FAR IN EXCESS OF THAT PRICE. IT IS MY EXPERIENCE, MR. CHAIRMAN, THAT ONLY MARGINALLY ECONOMIC SUPPLIES OF NATURAL GAS HAVE BEEN SUPPLIED TO THE INTERSTATE MARKET UNDER FPC PRICE REGULATION. FOR A FEW YEARS, WE HAD A SUBSTANTIAL SUPPLY OF SUCH GAS, BUT NO LONGER. EVERY RESPONSIBLE ASSESSMENT I HAVE SEEN OF PROSPECTIVE FUTURE GAS SUPPLIES INDICATES THAT THESE SUPPLIES ARE SUBSTANTIAL, BUT THEY ARE NOT MARGINAL BY ANY MEANS AND THEY WILL NOT BE FORTHCOMING UNDER THE PRESENT SYSTEM OF CONTROLS. THE FUTURE NATURAL GAS WILL COME FROM

THE VERY DEEP SEDIMENTARY BASINS THAT HAVE ONLY BEEN SUPERFICIALLY EXPLORED, FROM OFFSHORE AND ARTIC AREAS, AND FROM IN-FIELD DRILLING IN MANY OLDER FIELDS WHERE SKYROCKETING COSTS HAVE MADE SUCH DRILLING UNECONOMIC UNDER PRESENT REGULATED PRICES.

I DO NOT SEE, MR. CHAIRMAN, HOW CONTINUANCE OF POLICIES THAT INEVITABLY WILL KEEP US ON A DECLINE CURVE AS TO NATURAL GAS SUPPLIES CAN HELP ANYONE. THIS CANNOT HELP INDUSTRY, IT CANNOT HELP LABOR, AND IT CANNOT HELP RESIDENTIAL CONSUMERS. CERTAINLY, IT CANNOT HELP THOSE ON LOW AND FIXED INCOMES. TO THE CONTRARY, IT WILL CAUSE INCREASING PROBLEMS OF SHORTAGES AND HIGHER PRICES FOR ALL CONSUMERS OF THIS ESSENTIAL FUEL.

STATEMENT OF KENNETH C. VAUGHAN

TESTIFYING ON BEHALF OF
THE NATURAL GAS SUPPLY COMMITTEE

before the
SUBCOMMITTEE ON ENERGY AND POWER
of the
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
of the
UNITED STATES HOUSE OF REPRESENTATIVES

January 26, 1976

on
NATURAL GAS LEGISLATIVE PROPOSALS

H.R. 9464; H.R. 11245; H.R. 11047; H.R. 9165 and Title II of S. 2310

STATEMENT OF K. C. VAUGHAN

My name is K. C. Vaughan, 4414 Montrose Boulevard, Houston, Texas. I am a consultant to the petroleum industry and, prior to November 1, 1972, I was President of the Union Oil and Gas Division of Union Oil Company of California with primary responsibility for all its exploration and production activities in the United States. I was also a Senior Vice-President of the corporation and a Director and a member of the Executive Committee. In regard to natural gas legislation I have previously testified before this Committee, the Senate Commerce Committee, the Senate Finance Committee and the House Subcommittee on Communications and Power. My experience is briefly summarized in an appendix to my Statement.

I was requested to prepare the current Statement by your Committee pertinent to hearings now in progress regarding natural gas legislation pending in the House of Representatives. My testimony is made on behalf of the Natural Gas Supply Committee, a voluntary association of companies or individuals engaged in the production of natural gas.

The regulation of natural gas producers for nearly twenty-two years is not only one of the root causes of our current domestic energy shortages but the major cause of an imbalance in demand and supply. Had there been no regulation, natural gas supply and demand would be in balance and alternative fuels would have been further developed to reduce our reliance on insecure imports. The President of the United States,[1] the Federal Power Commission,[2] the Federal Energy Administration [3] and the Senate, as demonstrated by the passage of S. 2310, as well as recognized experts are in substantial agreement that the removal of price controls offers the best solution to maximize domestic supplies at lowest reasonable cost.

A totally free market would represent the best vehicle to correct past regulatory mistakes. The Natural Gas Supply Committee supports legislation which immediately deregulates new gas and phases out controls over flowing gas in four years. Unfortunately, Congress has not accepted out recommendations. Of the four proposals now pending, we firmly believe that adoption of the Krueger Bill, H.R. 11265, represents the best choice of four current alternatives.

Our selection of the Krueger Bill has been made after careful analysis of all Bills and amendments presently under consideration. There are many reasons for our choice as follows:

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[1] Remarks of President Ford before the Annual Meeting of the U. S. Chamber of Commerce. (4-28-75)

[2] Federal Power Commission, National Gas Survey, A Time for Decision and Action. (February, 1975)

[3] An Analysis of the Economic Impact of Natural Gas Deregulation, Technical Report 75-12. Draft, Federal Energy Administration. (3-18-75)

A. The Krueger definition of new gas is preferable.

1. Gas which continues to be delivered in interstate commerce after the expiration of a contract by its own terms.

The Krueger Bill, by including such gas in the definition of gas to be deregulated takes positive action to increase the economically recoverable reserves. This definition makes it possible for the producer to timely expend capital in anticipation of higher prices long before the field reaches marginal status and while remedial action is still warranted. Such action by the producer is very much in the consumer interest. It does no good to lock the barn door after the horses are gone. Even after production has reached marginal status gas produced can still be transported and distributed through existing amortized systems with an expenditure of direct cost only. Total deregulation of such gas can thus be effected within a reasonable time span while at the same time the price effects will be spread over a number of years and provide a cushioning of cost impact upon consumers.

Producers owning gas in this category have been the worst victims of the existing FPC Regulation. Much of this gas was discovered in the 1950's and earlier, through expenditures of capital which did not contemplate repressive regulation on the price of the product obtained. Imposition of "effective" regulation really began about 1960, with the inception of area rate regulation and in-line price regulation. From that time to this, the price of the gas (in constant dollars) has gone down, while costs levels in this industry have increased dramatically. The result is that gas producers today are unable to sell the gas which they own for enough revenue to enable them to replace those supplies through new drilling. To permit some of this gas, as contracts expire, to receive its market value will help to generate needed capital in the hands of those with the know-how, ability, and desire to stay in the gas business. Price incentives on gas to be found in the future, while commendable, are of little value without the capital required to take advantage of those incentives. Gas producers are people, or are corporations who employ people, who are experts in exploring for and producing gas. If they have the money, and if the incentives are there, exploration will take place and new supplies will result.

H.R. 11047 contains a similar provision which likewise will be effective in maximizing economically recoverable reserves from those fields where contracts will expire during the seven years after enactment.

S. 2310 does not exempt from regulation natural gas which is continued in interstate commerce after the expiration of a contract by its own terms and therefore is seriously deficient with respect to maximizing economically recoverable reserves. Providing that new rates be set for such gas each two years by utilizing cost-of-service methodology contains all of the fatal weaknesses attributed to similar determinations made in the past twenty-two years.

2. Gas produced from wells drilled to an existing reservoir.

The definition of "new" gas in H.R. 11265 is also superior to the definition in S. 2310, in that it includes gas from all wells commenced after the effective date, rather than only those wells which discover a new reservoir or extend an old reservoir.

Where increased prices make feasible the drilling of additional wells in old reservoirs there should be no inhibitions against such drilling. Many new reservoirs have been discovered in the process of drilling so-called development wells. Controversy as to what constitutes an extension well would be eliminated and such drilling represents the fastest means of increasing both reserves and deliverability.

B. The Krueger Bill is superior in its treatment of onshore gas.

The Krueger Bill, through the deregulation of onshore production, will allow interstate lines competitive access to new supplies. Producers could, for the first time in over 15 years, plan and proceed with confidence.

While superior to H.R. 9464, H.R. 11047 does not address itself to the long-term supply problem. Although more new gas can be developed in seven years than in one year (H.R. 9464), producers can hardly be expected to proceed on deep prospects in hostile environments that may take most of the seven years to complete.

S. 2310 contains similar provisions to the Krueger Bill in regard to onshore deregulation on new gas.

C. The Krueger Bill is superior in the treatment of offshore gas.

1. Treatment of royalty gas

The Krueger Bill does not provide for sale of the royalty gas by the Secretary of the Interior, a position we strongly endorse. There is ample competition for the purchase of any gas developed which will assure that the gas sold will be at the fair market price. We believe that the purchaser of the producer's share of the gas should have the right to also purchase the royalty share. Regulatory complications will be avoided and the purchaser who must spend capital for connection facilities will be assured of the total stream to justify such expenditures.

2. Contract term requirement.

A fixed contract term should not be legislated. The seller will want to negotiate terms of a contract that will recognize the need for prices sufficient to allow the discovery of replacements. The buyer will want to pay no more than a fair market price and acquire sufficient gas to justify his expenditure in capital. We see no problem in such parties arriving at a mutually satisfactory agreement on the contract term, as is done now. Further, it will avoid unnecessary argument relative to the life of the reserves to be sold, a fact that may be difficult to determine in the early stages of development.

3 H.R. 11047

This Bill is superior in that no ceiling is established on offshore gas sold after April 15, 1976. The Bill remains deficient, however, because of the limited time period.

D. The Krueger Bill is not complicated by an incremental pricing provision.

The Krueger Bill, and H.R. 11047 avoid extending regulatory end-use controls to consumers by allowing new natural gas price increases to be "rolled in" with with existing rates for old gas. The other Bills under consideration, H.R. 9159 and S. 2310 provide for "incremental pricing."

We recommend against the incremental pricing policy. While such proposal has a certain superficial appeal to users of residential and commercial gas, they are basically detrimental. If industry and agriculture are forced to pick up the increased burden it will be passed back to consumers in the form of increased product and commodity costs. Such pricing policy is discriminatory to residential and commercial customers who are unable to obtain natural gas and are thus forced to pay higher prices for alternative fuels as well as increased prices for products produced by industries utilizing natural gas. Uniform higher prices to all residential and commercial users will encourage conservation through additional insulation and the turning down of thermostats and will eliminate other wasteful uses.

Finally, in removing disastrous controls from producers, it would be a mistake to impose new costly regulatory controls and price fixing on consumers of natural gas.

Extraneous Issues

The clarification of several issues that have been continously exposed as "red herrings" is important in order that this Committee and the Congress can address themselves to the real issue - increasing our supplies of domestic energy. Those issues are; (1) improper reporting of reserves and withholding natural gas from the market; and (2) failing to comply with contractual obligations calling for minimum deliveries.

Improper Reporting of Reserves and Withholding of Natural Gas

Ultimate reserves or the precise volume recovery of oil and gas from a well or field is known only after the well or field is depleted and abandoned. Reserve determinations made early in the life of a field are subject to much greater error than those made after production experience has been gained. The closer a field approaches abandonment, the more reliable the reserve estimate. This explains why producers normally redetermine reserves periodically in order that previous estimates can be lowered or increased as indicated.

The procedures and formulas for reserve determination are standard and noncontroversial. The factors involved, however, are subject to interpretation and honest differences of opinion.

Using the same logs, cores, measurements of pressures, temperatures, etc. engineers and geologists can disagree on numerous factors. It is recognized that reasonable tolerances exist in most of the pertinent factors and although the disagreement referred to above may be within acceptable tolerances, one party using the upper limit of such tolerances can end up with a reserve determination much larger than the party using the lower limit of acceptable tolerances. This is so because of the compounding effect due to multiplying within the formula. Recoveries are influenced by other important factors such as the reservoir producing mechanism. Depletion type reservoirs that rely upon expansion, water drive reservoirs that rely upon the flushing action of water and combination reservoirs that rely upon both of the above mechanisms assert a strong influence on ultimate recoveries. Primary recoveries can vary in a gas reservoir from 30% to 90% and in an oil reservoir from 5% to 50%. As prices increase, ultimate recovery will also increase.

The real extent of a reservoir can only be approximated after discovery and can only be fixed after full development. Here again, depending upon chosen parameters, early reserve estimates can vary widely. In many instances wells are drilled on a spacing of one well to each 640 acres because of reserve size and economics. Such spacing is common in parts of Oklahoma and Texas. This means that the geologist or engineer estimating reserves must extrapolate or project information obtained in a 6" hole approximating .2 of a square foot over an area containing 27,878,400 square feet. This is a multiple of over 100 million times. We know from experience that mother nature is not very consistent or homogeneous in the way sediments have been deposited as you may have observed in river banks, road cuts or the Grand Canyon. From this example it isn't difficult to understand the problems connected with reserve determinations.

In conclusion, every accusation of shut-in wells or leases, and every charge of "rigged" reserve determinations have been thoroughl discredited. Your Committee has available to it, I am sure, investigations made by the FPC [4/], by the Natural Gas Supply Committee[5/] and by the Consolidated Natural Gas System [6/], the National Gas Survey by the FPC, and the FEA Reserves Study, released in 1975, and the Interior Department Statement issued by Dr. V.E. McKelvey, director of USGS, released December 12, 1974.

Recently, additional documentation discrediting these charges has been provided by the FPC in the investigation[7/] made by the staff of charges that suppliers of Transcontinental Pipe Line Corporation were withholding gas.

[4/] Report of FPC Bureau of Natural Gas and Office of Economics. (March, 1974)

[5/] Letter from C. M. Allen to Senator Adlai Stevenson III. (June 5, 1974)

[6/] G. J. Tankersly, Statement of American Gas Association before Senate Commerce Committee. (November 8, 1973)

[7/] F.P.C. Staff Investigation of Transco's Suppliers (Dec. 5, 1975

Having reviewed the physical factors influencing reserve estimation and recovery, I now turn to the economic factors. My discussion on reserves has been confined to proved reserves which are defined as the estimated quantity of crude oil, natural gas and natural gas liquids which analysis of geological and engineering data demonstrates with reasonable certainty to be recoverable from known oil or gas fields under existing economic and operating conditions. It follows then that an increase in price will increase economically recoverable reserves just as a decrease in price will reduce such reserves. Costs have the opposite effect. An increase in costs lowers economically recoverable reserves while an efficient operator who can reduce costs will extend the producing life of his well or field and increase such reserves. Because of the uncertainty surrounding natural gas prices reserve estimates can vary appreciably depending upon the value placed upon the product by the engineer or geologist.

In any dynamic system some wells will always be shut in. After a gas discovery is made, production cannot begin until the necessary production and pipeline facilities are constructed. Therefore, at any single point in time, there will always be some reserves in the shut-in category. If there were not, it would mean that no ongoing exploration is occurring. The North Slope has been shut in for years. Reserves are shut in in the Dos Cuadros field offshore Santa Barbara awaiting Department of Interior action. Many wells are shut in awaiting pipeline connection or work-over and many zones of multiple zone wells are shut in because they have been produced to depletion. Other temporary shut-in wells result from hurricanes or orders from the geological survey or State Conservation Agencies.

A related issue to the charge of withholding reserves is that of withholding natural gas by restricting deliveries below maximum. Here again, thorough investigations have failed to substantiate such accusations.[4] [5] [6] [7]

The subject of multiple zone wells where all zones are not producing simultaneously has also been a topic for abuse by those with little or no knowledge of industry operating practices. Single zone completions are most common, most trouble free and safer. However, dual and even triple completions have been made. No general rule can apply since each project must be analyzed on the basis of information pertinent to that project. In some instances where thick zones are present individual wells can be justified to each zone. Where many thin zones exist it is doubtful that additional drilling would be warranted. In such instances it is entirely possible that the total energy expended in such drilling would more than equal the energy found. Also, drilling new wells in partially depleted reservoirs sometimes results in irreparable damage to the producing zone.

A producer attempting to withhold gas from the market would be faced with serious obstacles. He would be risking drainage from adjacent leases; he would be violating actual or implied covenants in his contracts with the landowner or lessor; he would be running afoul of State Conservation Agency regulations; and in the offshore area violating USGS regulations, as well as facing a variety of Congressional investigations. Finally, the producer is fully aware of the time value value of money which deters withholding.

However, it is important to emphasize that if all the gas now shut-in could be made available the impact on our long-range energy problem would be essentially unchanged.

FAILURE TO COMPLY WITH CONTRACTUAL OBLIGATIONS

The latest barrage by opponents to the deregulation of natural gas has been an attack upon the transmission lines for not enforcing "minimum delivery" provisions in their contracts with producers. Those who choose to debate the issue are obviously unaware of practices in the industry and the intent of the parties at the time of contract execution. A brief history may be helpful. Many original gas sales contracts contained no delivery provisions and the producer relied upon the purchaser to allot to him a share of the purchasers market. Although all production from a field may have been committed, no specific volume was normally guaranteed. Deliveries fluctuated widely particularly between summer and winter. As the gas distribution system grew with demand, the producer, not the buyer, insisted upon some minimum take obligation so that he would be assured of a minimum revenue from his lease. This request was honored in exchange for a swing in deliveries to allow pipeline flexibility. Recognizing that minimum and maximum delivery provisions established in the initial period would be impractical and inconsistent with reservoir depletion the parties to the contract provided for future reductio that would reflect actual performance. The intent of the parties was to match deliveries with field capabilities. To do this theoretically so that the deliveries would reflect capabilities with time and field decline, would require almost constant change. Practically, however, such changes would only be made when either the producer or buyer so requested. In most instances within my experience, the rapid increase in demand resulted in purchasers pressing producers for maximum deliveries. Such demands made the maximum-minimum provisions useless and of no significance. This fact was recognized by both parties and no time or effort was wasted in setting new delivery rates.

To suggest that a fixed minimum delivery rate should be effective for the life of a contract in a field that will decline from maximum potential to deliver to zero potential ignores reality. That was not the original intent of the parties who concurred that the maximum and minimum delivery provisions of the contract were subject to the capacity of the reservoirs to produce.

As neither the producer, the pipeline, or the F.P.C. can make a field produce at more than its capacity, the real question being asked is whether the producer has developed and is producing the field as a prudent operator. Not only is this type of operation required by many gas sales contracts, it is also required by state conservation laws, USGS regulations on federal leases, and the oil and gas lease contracts with the landowner. Should the gas producer fail to develop and produce his lease in a diligent and prudent manner, he is subject to loss of his entire lease and all his investment under his oil and gas lease. He also may be subject to civil and criminal penalties under State Law. It is not reasonable to expect that a producer would risk such penalties by withholding gas in the hope of obtaining a price increase.

Fraser Bill H.R. 9159 (S. 692)

In my discussion of the other Bills under consideration no reference was made to H.R. 9151 the companion bill to the Natural Gas Production and Conservation Act of 1975, S. 692. Enactment of this Bill would be a giant step backwards in the nation's fight to reduce reliance upon insecure imports and to progress towards energy self-sufficiency. The inadequacies of the Bill are legion. In summary, the Bill would accomplish the following:

1. Extend regulation to the intrastate market blindly disregarding the basic elementary economic facts so well illustrated by experience with regulation in the interstate market where it has been demonstrated that fixing prices below market clearing levels will encourage consumption and retard exploration and production. The result will again be a self-induced shortage, inefficient resource allocation and higher prices at the burner tip.

2. Nothing in the Bill serves to mitigate current shortages;

3. Rather than decrease uncertainties new ones are added;

4. The Bill mandates the application of costing methodology which has proven inadequate and disastrous for over

two decades. It goes even further by fixing an initial base price between 40 cents and 60 cents per Mcf with rates to remain in effect for five years. Ironically, such price levels are already out of date even in the eyes of some of its proponents who now propose a statutory "new" gas price of $1.30 per Mcf. Such action emphatically demonstrates the futility of attempts to outguess the free market by statutory ratemaking or price fixing;

5. Major oil companies are prohibited from engaging in joint ventures directly or indirectly thus prohibiting future unitization that has been approved in the past by lessors, by States and by Federal bureaus in order to maximize ultimate economic recovery;

In conclusion, H.R. 9159 adds new complications to an already complex regulatory situation. What is needed is a clear-cut deregulation bill but, short of that, any bill enacted should have as a primary goal an increase in our domestic supply of natural gas.

BACKGROUND STATEMENT - K. C. VAUGHAN

I graduated from the University of Southern California in 1933 with a Bachelor of Science degree in petroleum engineering. Following my graduation I joined Union Oil Company as a wellpuller. During subsequent years I held such positions as Production Superintendent in California, Manager of Field Operations in the Western Region, and Manager of Natural Gas and Gas Liquids Division. In 1959 I was named Manager of Union Oil's Gulf Division in Houston, in which capacity I supervised all of Union's exploration and development activities in the States bordering on the Gulf of Mexico. In December 1963 I returned to Los Angeles as Senior Vice-President in charge of exploration and production for the corporation. In January 1969 I was elected President of the newly created Union Oil and Gas Division. In this latter capacity I was responsible for all of Union Oil's domestic exploration and development activities and the natural gas and gas liquids functions of the company are among the activities which were under my supervision. I retired from Union Oil on November 1, 1972 and opened an office in Houston as a Petroleum Consultant to industry. I have made appearances as a witness before various State and Federal agencies, including the Federal Power Commission, the California Public Utility Commission and Congressional committees concerned with proposed legislation to amend the Natural Gas Act. In addition to my consulting activities, I have joined the Boards of Directors of Petrolane, Inc., Texas Gas Transmission Corporation, and Cordon International Corporation.

THE STATE OF TEXAS X
COUNTY OF HARRIS X

KENNETH C. VAUGHAN, being duly sworn, deposes and says that he is a Petroleum Consultant authorized to verify and file this document, that he has examined the statements contained in this document and that all such statements are true and correct to the best of his knowledge, information and belief.

Kenneth C. Vaughan
Kenneth C. Vaughan

SUBSCRIBED AND SWORN to before me, a Notary Public of the County of Harris, State of Texas, this 23rd day of January, 1976.

Notary Public in and for
Harris County, Texas

My Commission Expires June 1, 1977

STATEMENT OF
RICHARD L. O'SHIELDS, CHAIRMAN
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA
BEFORE THE SUBCOMMITTEE ON ENERGY AND POWER
OF THE COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
HOUSE OF REPRESENTATIVES
RE: LONG-TERM NATURAL GAS LEGISLATIVE PROPOSALS

JANUARY 26, 1976

Mr. Chairman and members of the Subcommittee on Energy and Power. My name is Richard L. O'Shields. I am President and Chief Executive Officer of Panhandle Eastern Pipe Line Company, Houston, Texas. I am also Chairman of the Board of the Interstate Natural Gas Association of America (INGAA) for whom I am appearing here today. INGAA, as you know, is a national non-profit association representing virtually all of the interstate pipeline companies operating in this country.

My company, together with our major subsidiary, Trunkline Gas Company, are members of INGAA. We operate more than 14,000 miles of pipeline connecting major producing areas in the Gulf of Mexico, Louisiana, Texas, Kansas, Oklahoma and Colorado with natural gas consumers - principally in the states of Michigan, Illinois, Indiana, Missouri and Ohio.

We supply 130 utility and municipal customers who, in turn, serve a market area of 24 million people in 12 states. We are not the only pipeline company operating in this area, but we are a major source of energy supply. Natural gas is a critical energy in this area with its heavy concentration of homeowners, agriculture and industry.

We, along with practically every other major pipeline company in this country, are faced with a severe and growing shortfall in gas supplies available to our system. As a consequence of these shortages Panhandle, since 1972, has been forced to institute increasingly larger annual curtailment levels on its customers and, unless substantial changes are made in the legislative and regulatory climate under which we operate, the situation is going to get far worse before it gets better. I can assure you, Mr. Chairman, that were it not for the warmer than normal winters we have experienced over the last three heating seasons, the gas shortages could have reached very severe proportions for a large segment of our population and our economy. Even with the warmer than normal weather, on our system alone we have been meeting only about 73 percent of our customer entitlements. Our interstate pipeline gas sales declined from 1.09 trillion cubic feet in 1971 to about 825 billion cubic feet in 1975, a 24% decline in four years, all due to declining supplies. On a national basis, U.S. marketed production of interstate gas peaked in 1971 at 13.7 trillion cubic feet and has declined to less than 12 trillion cubic feet in 1975.

I mention these facts, Mr. Chairman, because there seems to be some doubt in the minds of some that there is a gas shortage. I can tell you firsthand that there is a shortage of natural gas - it is real and each day we lose in getting remedial legislation, it grows more severe. The Congress is the only body who can do something about it. Meaningful legislation is needed. It should be done now.

Your Subcommittee has before it a bill, H.R. 11265 introduced by Congressman Krueger, together with a number of co-sponsors, which, in our considered view, would provide the kind of relief needed to generate more natural gas production and greatly enhance the search for new reserves of this vital natural resource. Title II of this bill is similar, in many respects, to S. 2310 which passed the Senate last October, but, as I will explain in a moment, without some of the objectionable features of S. 2310.

The Letter of January 20, 1976 from Chairman Dingell requesting me to appear indicated that the Subcommittee would like our comments to be addressed particularly to the "new gas" definitions contained in S. 2310 and H.R. 11265. We will do this and also comment on other specific matters which we consider critical. INGAA has made available to the members of the Subcommittee marked up versions of S. 2310 and the Krueger bill, pinpointing and explaining, where appropriate, the various changes which we believe should be made.

Definition of "New Gas"

Both S. 2310 and H.R. 11265 contain definitions of "new natural gas." The major difference is that the Senate bill delineates on a physical basis truly new gas. We endorse the S. 2310 definition.

Under the S. 2310 definition new gas available to the interstate market would include:

1. Gas from wells drilled after January 1, 1975, which has not previously been dedicated to the interstate market.

2. Gas already in production and being sold in the intrastate market.

3. Gas from newly discovered reservoirs onshore or underlying state waters.

4. Gas from newly discovered reservoirs in the Federal offshore which is sold under a long-term contract. (All gas from the Federal offshore is in the interstate market. In order for any such newly discovered gas to be eligible for classification as new gas, it must be sold under a long-term contract.)

5. Gas produced from extensions of existing reservoirs, both onshore and offshore.

6. Gas presently being sold to the interstate market

under limited-term certificates (five years or less) or temporary emergency certificates. (Delivery of this gas could be continued in the interstate market; otherwise it would no doubt end at the expiration of the certificate or the emergency contract.)

Newly discovered reservoirs and extensions to existing reservoirs, regardless of whether the lands on which they are located were committed to the interstate market, are considered to be new gas. The objective is to permit all newly discovered or newly developed natural gas reserves to qualify as "new" natural gas under the law. This approach, in our opinion, will encourage increased drilling and development of new gas reserves yet, at the same time, will assure that "old" gas does not become "new" gas as some critics of deregulation have charged will be the case.

The S. 2310 definition also assures continuity in the sale of flowing gas to interstate pipelines under existing arrangements and will prevent the disruptive shifting of sales (and reserves) as between pipeline purchasers or to the intrastate market as old contracts expire. It also will serve to prevent the potential problem of new wells being drilled into old reservoirs solely for the purpose of qualifying for "new" gas treatment with no concomitant increase in supply.

With respect to offshore reserves in the Federal domain, long-term commitments of gas - 15 years or life of the reservoir if less than 15 years - are extremely important so far as the pipelines are concerned because of the high cost associated with the construction of offshore facilities and the need to assure the economic and financial feasibility of offshore projects.

For these reasons, we would urge that Title II of H.R. 11265 be amended to include the "new" gas definition as set forth in Title II, Sec. 204, paragraph (8) of S. 2310.

Incremental Pricing of New Supplies

Both S. 2310 (Section 28) and H.R. 9159 (Section 206) require that higher cost, new supplies be sold by the interstate pipelines under incremental pricing. H.R. 11265 does not contain such a requirement.

The administrative and regulatory problems which would arise from incremental pricing are monumental. More importantly, however, such a provision could be self defeating by seriously undermining the ability of the pipelines to meet the essential needs of all their gas customers.

Historically pipelines have been able to sell gas to their customers on a "rolled-in" basis, adding higher cost, new gas to the existing supply and selling gas to distributors on an averaged or "rolled-in" rate. This has enabled all distributors to absorb the cost and meet the needs of all customers on an equitable basis. The incremental pricing proposal would establish by statute a discriminatory pricing structure which could materially impair pipeline distribution customers in rendering and planning their gas service. This is a very complex problem involving numerous factors such as the continual shifting of gas needs as between different categories of customers (residential, commercial and industrial) depending on weather, geographic location, time of year and level of industrial activity. It would simply be infeasible to administer rates which allocate higher cost gas to one segment of the market and lower cost gas to another when the end use literally shifts from day to day. This is further complicated by changes in the mix of old and new gas which will occur.

Further, such a provision might deprive smaller distributors and their customers of the opportunity to buy new gas as it becomes available. Small distributors may be prevented from contracting for higher cost new gas for their existing service areas because they do not generally have large industrial customers capable of committing for new gas volumes.

Further, it seems only obvious that industrial users who would be required to pay the higher price for new gas would naturally try to obtain assurance of a continuity of supply. This would create a conflict between the type of service rendered to industrial customers on the one hand and residential and small commercial users on the other. This could be particularly disruptive as between industrial customers in one area and residential and commercial users served by another distributor in another area.

Another vitally important aspect of this problem that seems to be overlooked is the impact of incremental pricing on new, costly supplemental gas supply projects such as coal gasification, liquefied natural gas (LNG) and synthetic gas. The price of this gas will probably range from $1.50 to $4.00 per thousand cubic feet (Mcf). If such gas must be priced incrementally and the cost not rolled-in with old or conventional sources of supply, it could well sound the death knell for many of these projects which we believe will be essential in the next few years.

As we see it, the additional cost of "new gas" that may be discovered, when rolled-in in the traditional way, will not be as severe a price impact on the consumer as may be feared. As a consequence, therefore, we see no advantage to mandating incremental pricing of new gas and strongly urge the Subcommittee not to include such a provision in any bill you report out for consideration by the House.

Federal Royalty Gas

Section 31 of S. 2310 would require the Secretary of the Interior to take Federal royalty gas in kind and sell it at fair market value by competitive bidding at the time of commencement of production. Although it appears to us that there is some error in the wording of Section 31 as printed, we assume that it is intended to apply only to leases issued after the date of enactment of the bill. Certainly, if Section 31 is to be retained, and we are convinced it should be deleted, it should be only prospectively applied to future leases and the Secretary of the Interior should have discretion, rather than an absolute mandate, to apply it.

Even with such modification, however, the requirements of Section 31 would have a seriously disruptive effect on the natural gas supply picture. In the first place, it would adversely affect the economics and planning of offshore pipeline systems. If the royalty gas is not to be disposed of until the commencement of production from the lease, pipeline companies would be faced with the imponderable problem of trying to plan and construct pipeline projects without knowing whether they would receive six-sixths (6/6) or five-sixths (5/6) of the gas involved.

In the second place, forcing gas pipelines to bid for the royalty gas, after having constructed facilities to the lease, would probably result in higher consumer prices without any accompanying incentive on anyone's part to develop new supplies. Further, the uncertainty of not knowing whether the royalty gas would be available would be a disincentive for the offshore interstate pipelines who conduct exploration and development on such leases.

Finally, we think the authority given to the Secretary to limit the participation of competitors for royalty gas of this type to those pipelines servicing regions where there is an emergency shortage of natural gas is tantamount to allocation of gas and would unfairly create serious supply problems for those companies and their customers from whom such royalty gas would be taken.

We strongly urge that Section 31 of S. 2310 be deleted.

Pipeline Production

I must note that an amendment has been presented for floor consideration when natural gas legislation is debated which would amend the definition of new gas contained in the Krueger bill.

This amendment, proposed by Mr. Eckhardt, would change the definition of new gas so as to apply only to production by an independent producer. The effect would be to deprive pipelines and their affiliates of the competitive price for new gas production. This obviously would inhibit, if not prevent, pipelines and their affiliates from engaging any further in the much needed exploration effort for new gas.

INGAA believes this would be completely counterproductive. Natural gas is the lifeblood of the pipelines. The nation's pipelines have used every avenue available to them to stimulate production. Foreclosing pipelines from gas exploration would reduce total exploration efforts in a time of shortages when maximum exploration efforts and investment are needed. Such a move would hardly serve the public interest.

Let me cite our case as an example. The impending gas supply shortage lead the Panhandle companies in 1970 to develop a vigorous program for the acquisition and development of new supplies. Since that time we have spent over $250 million on lease exploration and development for new gas in supply areas which could be made available to our pipeline systems. Our efforts have been concentrated in the Gulf of Mexico, the Anadarko Basin, and Colorado and Wyoming. As a result of these efforts we have fortunately been able to discover gas and put together gas supply projects in all of the listed areas. These efforts have already generated important volumes of gas for our customers and we expect them to contribute substantial additional volumes in the future. These efforts are increasingly more costly, however. We must be able to anticipate a fair profit or we will not be able to finance, and therefore continue, these efforts. Had we been prevented from exploring for gas, the $250 million invested by our company would not have been invested in exploration.

Other pipelines have taken similar action to help their own natural gas supply problem. I recite Panhandle's experience merely as an example.

While pipelines, because of financial limitations, cannot develop all their needed gas supplies and must look to independent producers for the major portion of them, pipeline exploration efforts nevertheless are important supplements to those of producers. Any action which would inhibit pipelines from continuing their self-help production operations would simply hurt the consumer. We have been a constructive force in the production of natural gas - we expect to continue to be.

Further, any attempt to legislate that pipeline companies divest their production activities would also be a tragedy in that the added gas exploration efforts of the pipeline industry would be lost at a time when the country needs all the exploration activity it can generate.

Conclusion

Mr. Chairman, I cannot emphasize too strongly that the public interest requires prompt, effective action by Congress.

H.R. 11265, modified as we suggest, would provide the basis for expanded investment and effort in the high-risk venture of exploring for natural gas.

We hope Congress will see this as a proper initiative in helping to solve a problem which has been around too long.

Thank you for this opportunity to appear.

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STATEMENT OF DR. PAUL DAVIDSON
PROFESSOR OF ECONOMICS AND ASSOCIATE DIRECTOR OF THE BUREAU OF ECONOMIC RESEARCH AT RUTGERS - THE STATE UNIVERSITY OF NEW JERSEY

HOUSE SUBCOMMITTEE ON ENERGY AND POWER
January 27, 1976

My name Is Paul Davidson. I live at 18 Turner Court, Princeton, New Jersey. I received a Bachelor of Science degree from Brooklyn College in 1950, a Master of Business Administration degree from City College of New York in 1955 and a Ph.D. in Economics from the University of Pennsylvania in 1959. I was a member of the Economics Department of the Wharton School of Commerce and Finance of the University of Pennsylvania and taught there during the periods of 1955-1958 and 1961-1966. From 1958 to 1960 I was Assistant Professor of Economics at Rutgers University. In 1960-61, I was Assistant Director of Economics Division of the Continental Oil Company. In 1964-65, I was Visiting Lecturer and Fulbright Scholar at the University of Bristol in England. In 1970-71, I was a Senior Visitor at the Faculty of Economics and Politics of the University of Cambridge (England). I have held my current position at Rutgers since July 1966.

I am the author of a book entitled *Theories of Aggregate Income Distribution* (Rutgers University Press, 1960) and one entitled *Money and the Real World* (Macmillan, 1972). I have coauthored books entitled *Aggregate Supply and Demand Analysis* (Harper and Row, 1964), *Milton Friedman's Monetary Framework* (University of Chicago Press, 1975), and a monograph entitled *Demand and Supply of Outdoor Recreation* (Bureau of Outdoor Recreation, 1969). I am the author of numerous articles on various economic subjects which have been published in professional journals such as *The American Economic Review*, *The Economic Journal*, *Oxford Economic Papers*, *Canadian Journal of Economics and Political Science*, *Public Finance*, *Econometrica*, *Land Economics*, *The Sourthern Economic Journal*, *The Natural Resources Journal*, *Review of Economics and Statistics*, *The Journal of Political Economy*, *Economic Inquiry*, *and the Brookings Papers on Economic Activity*.

My interest in the economic problems of the oil and gas industry can be traced back to 1960 when I was the Assistant Director of the Economic Division of the Continental Oil Company. Since then I have analyzed economic aspects of oil and gas in professional articles, in testimony as an expert witness before the Federal Power Commission and various congressional committees, as a member of the Supply-Technical Advisory Committee of the National Gas Survey, and in the past few years as a consultant to the Ford Foundation's Energy Policy Project where I was the senior investigator on a study entitled "The Relations of Economic Rent and Price Incentives to Oil and Gas Supply," and as a member of the *Brookings Economic Panel* where I was the senior investigator of a study entitled "Oil: Its Time Allocation and Project Independence."

The purpose of this statement is twofold. Since this hearing is primarily involved with the natural gas shortage, the main objective of this presentation is to demonstrate why a free market (or de-regulation) in natural gas production in the United States will, under present circumstances, aggravate the current gas "shortage" and energy crisis by encouraging behavior of producers which cannot be in the public interest. (This does not mean that the current regulatory policies of the

Federal Power Commission are ideal; I will recommend some possible changes in regulatory policy.)

A second objective of this statement will be to briefly indica what I believe are the necessary components of a National Energy Policy (NEP). As a result of my recent studies for Brookings and the Ford Foundation Energy Policy Project I have developed a 9 point NEP which should provide a solution to the energy problem without exacerbating our current inflationary and unemployment problems.

I. AN ANALYSIS OF THE SUPPLY OF NATURAL GAS

To understand the so-called shortage of natural gas it is important to provide a realistic analytical framework for viewing the economic factors which underly the long run supply of natural gas reserves. Such a basic framework will provide a basis for judgment about the meaning of recent gas supply trends.

Although my statement is not dealing solely with the question of the desirability of regulation of the wellhead price of natural gas, nevertheless the objectives of regulation cannot be ignored in any discussion of the efficacy of incentive proposals, for efficiency must ultimately be determined in relation to the goals of social policy. If a free market--that is, an unregulated market--produced results that were in the social interest, there would be no need to regulate the wellhead price of natural gas. Accordingly, I believe that those charged with the responsibility of social decision making--the legislative, executive and judicial branches of the Federal Government were correct when they concluded that it is in the social interest to prevent the wellhead price of natural gas from reaching the level that might be attained in an unregulated market given the existing institutional arrangements in this industry. Moreover, I believe this view is compatible with the traditional American concepts of fairness, since in an unregulated market for natural gas even larger unearned windfall economic gains would accrue to certain individuals than currently exist. These windfalls are called economic rents.

A primary purpose of price regulation is to limit the ability of sellers to set price in the regulated sector in order to prevent the exploitation of a market situation. Specifically, the social object of regulation is, therefore, to obtain a particular product or service at the lowest supply price consistent with the following objectives:

(1) assurance of a continuing supply

(2) encouragement of a program of technological progress in leading to cost and therefore supply price reductions

(3) fair treatment of both the consumers of the product and the investors in the producing firms.

If a free market could do a reasonably good job of simultaneously achieving these objectives, there would be no need for public regulation. If the unregulated market cannot, the regulation must be introduced which will improve performance, while minimizing the possibility that individuals or particular groups should receive any significant economic windfalls merely as the result of the outcome of the Regulatory Agency's or Congressional decisions.

The supply price is a well established concept in economics. It is defined as the price "which is sufficient and only just sufficient to make it worthwhile for people to set themselves to produce the aggregate amount." In other words, it is the "price required to call forth the exertion necessary for producing any given amount of commodity." (Both quotes are from Alfred Marshall, Principles of Economics, 8th edition, pp. 373 and 142, respectively.)

If, in the long run, the supply price is not earned, then ultimately the effort necessary to produce the particular product will not be forthcoming. If, on the other hand, more than the supply price is paid, the product will continue to be produced, but the suppliers will receive income in excess of what they would have been willing to take for their efforts. These excessive incomes are economic rents. Thus, if more than the supply price is being paid, the social objective of fair treatment is being violated, as consumers are being required to pay more than is necessary to obtain the quantity of the product desired. Moreover, it is possible to withdraw these rents from producers and landowners without causing a curtailment in supply.

Domestic gas producers have been suggesting for many years that an increase in price is necessary to induce them to increase the effort necessary to develop additional reserves. The producers do not deny that the current ceiling price is sufficient incentive for developing some new reserves each year--only that insufficient additional new reserves are coming forth to meeting production demands in the future.

The questions that currently face the Federal Power Commission and the Congress is therefore to decide if (a) is it in the social interest to accelerate the present rate of development of additional gas reserves, (b) if it is, how much additional reserves will be forthcoming as a result of either any given requested price increase or decontrolling gas prices, and (c) how could such an increase in wellhead price be held only to the minimal amount which is necessary to bring forth the desired additions to annual new reserves--so that a large portion of the burden of the additional costs placed on consumers will not go merely to create large additional unearned and unnecessary windfalls, i.e. economic rents, for producers and property owners. If the latter occurs, then for any given increase in price, most of it will go to increase the wealth of mineral rights holders--both royalty owners and producers--and very little will act as an incentive to bring forth additional reserves. If the latter situation is applicable, it is the responsibility of the Commission and Congress to search for alternative policies which provide incentives to provide additional reserves--alternatives to permitting a rise in the wellhead price of all gas produced. Ultimately therefore, the economic questions are (1) whether past trends in the industry indicate that the current regulated wellhead prices are at an inadequate level to provide sufficient gas supply and (2) if it is determined that the current wellhead price is below the lowest supply price necessary to bring forth adequate reserves, what is the fairest method for encouraging an acceleration of development of gas reserves without burdening consumers with paying huge additional economic rents.

In order to interpret and understand past trends as well as to set out guidelines for rational policy, it is necessary to develop some sort of analytical model of the natural gas industry. The purpose of all analytical models is to aid in making inferences about the uncertain future. The simplest of all models would involve mere extrapolation of past trends. This approach, although it can be useful, has severe disadvantages, namely that such an approach, by itself, provides little insight as to the causes of these trends and hence can provide only a limited range of policy solutions. In other words, an extrapolative project of the reserve/production ratio, by itself, tells us nothing about the behavioral response of gas producers to a wide variety of economic and political variables, nor how changes in these variables will encourage producer efforts to find and sell reserves. What is required is the setting out of an economic model which, at a minimum, explains what determines the offerings of gas reserves to the market. The annual flow of new reserve offerings to market is likely to be a function of a number of variables--and the current wellhead price is only one of them. Thus, any model which focuses solely on current wellhead price is likely to be misleading.

1. The Difference Between a Textbook Model of the Gas Industry and the Real World

To understand the supply relationships of the natural gas industry requires some important modifications of the traditional textbook economic model of an industry, for the traditional approach utilizes many simplifying assumptions which are not applicable to the case at hand. For example, the traditional model assumes:

(1) perfect knowledge of all aspects of the market at present, as well as perfect foreknowledge about the indefinite future

(2) no individual buyer or seller can influence the market price

(3) haggling and recontracting occurs in the market until both the buyers and sellers are satisfied with the market price

(4) supply is primarily related only to current production; the availability of pre-existing stocks produced in earlier periods are usually ignored.

Utilizing such simplifying assumptions, many economists tend to focus solely on the current market price and the price elasticity of supply as the sole determinant of the current offerings in the market.[1]

These assumptions do not apply in the gas industry; other factors become as relevant as current price in explaining supply. These factors include, among others, (1) the existence of previously developed stocks of gas reserves and of underground but as yet undeveloped inventories of the durable commodity; (2) the inevitable uncertainties and expectations about the future and the existence of long term contracts which restrict haggling even though more information may become available (while permitting sharing of the burdens of uncertainties among the property owners, producers, and pipelines); (3) the existence of numerous governmental (regulatory, fiscal, monetary and trade) policies which impinge on production and investment decisions. Hence, before anyone attempts to draw inferences from traditional economic industry models, these must be modified to take account of these essential characteristics of the natural gas market. Because of these complexities, the development of a completely detailed model of the industry would be too lengthy to be possible here. Nevertheless, for the purposes of providing qualitative insights, I believe I can, at this time, suggest a model of the supply side of the natural gas industry.

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[1] For example see P. W. MacAvoy and R. S. Pindyck, "Alternative Regulatory Policies for Dealing with the Natural Gas Shortage," Bell Journal of Economics and Management Science, IV (1973).

The supply of new reserve offerings must be viewed as dependent on several variables; the primary supply-affecting variables are:

(a) the present wellhead price and the market requirement of producers entering into long term forward contracts without most favored nation clauses;

(b) exploration, development and production costs;

(c) the rate of interest; and

(d) user costs, that is, costs which are dependent on expectations about future wellhead prices and market conditions in markets for alternative fuels.

Accordingly, changes in user costs and/or interest rates can affect annual gas reserve additions even if the current wellhead price and costs are unchanged.

A traditional textbook model of the natural gas industry, such as the aforementioned MacAvoy and Pindyck model, assumes that the bringing forth of gas reserves is a reproducible process which occurs under conditions of increasing real costs or diminishing returns to resource inputs. No one will deny that in a given state of technology, the natural gas industry may operate under the law of diminishing returns and therefore exhibit increasing resource costs. But where these textbook models err, in my view, is to assume that increasing real resource costs are the only component of the supply price and therefore these models assume that the elasticity of the real resource cost function is the same as the supply price elasticity. For example, MacAvoy and Pindyck state "An equation for marginal development costs [is] the 'supply curve' for production in field markets" [p. 467]. This could be true only if user costs were zero,[2] a condition that has not characterized the situation in the United States over the last decade.

Furthermore the traditional textbook model also ignores interest rate changes which will have an important impact on additions to total reserves. Since interest rates have systematically increased over the last decade, a realistic model must also deal with interest rate phenomena.

Since the traditional textbook models of the supply behavior of a firm or industry excludes user cost phenomena, the implications that are derived from such models are not only misleading, but they can suggest policies which may be socially undesirable--and in this case might even worsen the gas shortage. As John Maynard Keynes noted in his famous book, The General Theory of Employment, Interest and Money "Supply price is,

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[2] It also assumes a purely competitive field market.

I think, an incompletely defined term, if the problem of defining user cost has been ignored .... I argue that the exclusion of user cost from supply price ... is inappropriate to the problems of the supply price of a unit of output for an individual firm" (p. 55n).

To see why the traditional model which excludes user costs is misleading, let us compare the implications of the traditional model with those of a model which explicitly allows for user costs and interest rate charges.

2. The Traditional Textbook Model

If increasing resource costs are an inevitable outcome of increasing the annual offerings of new reserves, and if user costs are excluded, then it follows that if the current wellhead price is just sufficient to bring forth the current flow of annual reserves then the price will have to increase in order to encourage the profitable development of larger annual reserves. If, as the traditional model assumes, the *only* factor holding back greater reserve offerings is increasing real resource costs, then in a competitive market[3] the quantitative relationship between the percentage change in wellhead price required to bring forth a percentage change in the quantity of reserves offered, i.e., the supply price elasticity, is equal to the elasticity of real resource costs. For example, if to produce ten percent more reserves per annum requires an increase in resource costs of five percent, then the resource cost elasticity (which by assumption is the supply price elasticity) is equal to two.

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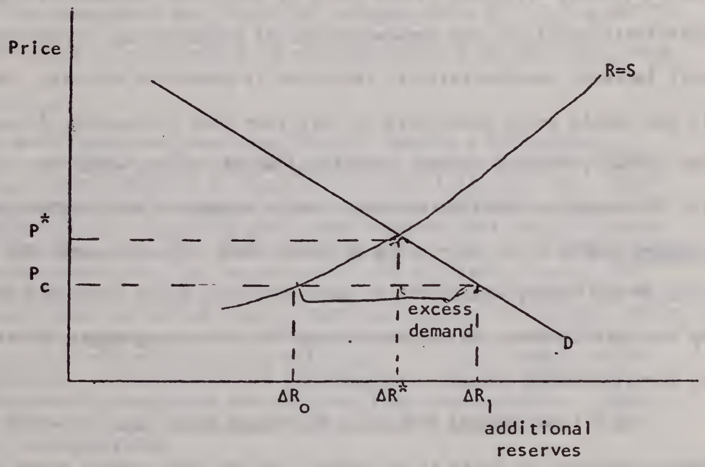
[3] Or in a market when the degree of monopoly is unchanged. (See P. Davidson, L. Falk and H. Lee, "The Relations of Economic Rent and Price Incentives to Oil and Gas Supplies" in *Studies in Energy Tax Policy* by G. M. Brannon (Ballinger Publishing Co. Cambridge, Mass. 1975)

Figure 1, which is a reproduction of a diagram appearing on p. 463 of the MacAvoy and Pindyck paper, shows a rising marginal resource cost curve (R) which is assumed to be, in the traditional textbook models, the supply curve(s) of the industry.

Figure 1



The elasticity of the supply curve is the crucial measure of the response of producers to market price incentives. If the supply response is infinitely elastic, no price increase is required to stimulate additional offerings. If the elasticity is less than infinite then, all other things being equal, price must increase if additional annual reserves are to be brought to market. If the elasticity is elastic, i.e., if its magnitude is between unity and infinity, a large proportion of the price increase goes to stimulate additional offerings and only a small proportion of the price increase goes to increase the windfall economic rents of producers and land owners. If the supply response is inelastic, i.e., if its magnitude is less than unity, then the additional offerings called forth by any price increase will be relatively small and the economic rents of producers and landowners will increase substantially if the price is permitted to rise. Finally, if the supply price elasticity is less than zero or negative (a case not normally handled by the traditional model but one which our realistic alternative model as developed below suggests) then higher prices reduces supply while increasing economic rents. Consequently the magnitude of the supply elasticity is crucial to the issue as to whether and by how much increase in wellhead prices will increase supply offerings or merely provide economic windfalls.

As I have already indicated the traditional model of which the MacAvoy-Pindyck analysis is an example, assumes that supply elasticity only reflects real resource costs as user costs, that is expectations about future changes, are ignored. Thus in the MacAvoy-Pindyck analysis of Figure 1, "Under conditions of shortage, the regulated ceiling price P_c prevails rather than the market demand price P^* ..[and] the quantity realized [ΔR_o] is on the supply but not demand function" [p. 463]; and according to MacAvoy and Pindyck there is an excess demand for reserves or a gas shortage. In this model, the apparently obvious solution is to permit the price to rise to P^*; at this price demand and supply are equal and the shortage has been eliminated by the free market.[4]

In the real world, however, both expectations about future prices and market conditions (user costs) and interest rate have changed over the last decade and that is why it is dangerous to view the decline in the observed reserve/production (R/P) ratio, by itself, as indicative of a gas shortage caused by increasing resource costs of finding new reserves which can only be cured by a substantial rise in the field price of natural gas. The actual change in the R/P ratio over time is the net result of changes in all the factors listed above which affect supply and it is not necessarily due to a current regulated wellhead price which is less than either the free market price or marginal resource costs of developing additional reserves.

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[4] MacAvoy and Pindyck estimate that it will require a 249 percent increase in new field prices by 1980, increase annual reserves by 353 percent, thereby implying a resource cost elasticity of 1.42. Their implied quantitative estimates of supply price elasticity is, however, of questionable statistical significance because their Durbin-Watson (D-W) statistics show that their results are marred by serious serial correlation problems. The low values of the D-W statistics of .36, .74, and 1.06 (pp. 477-8) indicate that the t-test for significance of the estimated price and other parameters are not valid, hence there is no way of knowing that the authors have properly quantified the price or other effects on supply offerings. In fact, severe serial correlation is compatible with a quantitative model in which one or more important factors have been omitted from the equations. Could the exclusion of user costs explain the low D-W statistics? It is at least a possibility.

3. An Alternative Model of Natural Gas Supply

We can define an interest elasticity for new gas reserves which measure the percentage change in reserves for any given percentage change in interest rates, all other things remaining equal. Similarly, there is an elasticity of user costs which relates the percentage change in gas reserves offered in a period to the expected percentage change in price at some future date. For reasons I would like to develop in a moment, the interest elasticity is likely to be negative, that is a rise in interest rates will, all other things unchanged, lead to a *decrease* in offered reserves relative to production. Similarly and probably more importantly the user cost elasticity is probably negative, so that an expectation of an increase in the future wellhead price relative to current price will, all other things being equal, lead to a decline in current offerings. Professor A.E. Kahn of Cornell and Chairman of the New York Public Service Commission alluded to this negative user cost elasticity in his FPC Docket AR61-1 testimony when he noted "the holding of supplies off the market in anticipation of rising prices . . . imparted a negative elasticity to supply"(Tr 7095).

In sum, the observed supply response of reserves over time is a resultant of the various positive and negative elasticities involved and the actual relative changes occurring in interest rates, expectations, and wellhead prices relative to resource costs during the period of study. Simply assigning the past declining R/P ratio trend to rising resource costs with a regulated price, as MacAvoy and Pindyck implicitly do, involves an assumption that user costs and interest rate changes have had no effect on reserves relative to production in the past nor will they in the future. On the other hand, recognition that the observable past trend is a net resultant of various countervailing as well as augmenting forces operating with different elasticity impact on the R/P ratio will immediately permit those involved in these hearings to engage in a more meaningful discussion and analysis of the alleged gas shortage and the future supply prospects for gas.

The data merely shows the statistical series which purports to show the reserve/production ratio declined erratically during the late fifties and early sixties, but it has shown a steady and more severe decline ever since. Without commenting on whether this statistical series is an appropriate measure of supply offerings, let us, for the sake of discussion, assume that the series is an accurate measure of the trend in supply. How then should the erratic decline in the early period and the more steady decline of the later period be interpreted? It is at this stage that all the real world characteristics that I enumerated earlier--such things as the existence of contracts, inventories of durables, etc.--become important in providing useful insights.

A. Interest Rates and Reserves. Natural gas in the ground is a durable, relatively standardized commodity which can be carried at low costs, particularly at early stages of the development of a gas property. Any commodity which is in general demand and which has these characteristics of durability, standardization, and low carrying costs can be viewed as (1) capital assets in the sense that they are associated with a potential future income stream, and as (2) objects of potential speculative activity.

The present value of the expected future income stream of any such inventory of a durable good will depend on the expected future prices and costs of production, discounted by the rate of interest. Hence, a rise in the rate of interest, even if all other things remain equal, lowers the present value and therefore reduces the incentive to search out and hold such goods in inventory. Accordingly, the interest elasticity with respect to inventories is negative. Once it is recognized that the proven reserves statistics represent inventory holdings, it should be expected that holding of proven reserves relative to production will decline as interest rates increase. The magnitude of such a change will depend on the interest elasticity effect on proven reserves, all other things being equal.

The question of reserves is essentially a question of maintaining a sufficient inventory level relative to production (sales). It is possible to develop a classification scheme where underdeveloped but known fields are viewed as raw material inventory, fields under development as a work-in process inventory, and fully developed fields or proved reserves as shelf-inventory. For our purposes here, the exact demarcation of the various inventories is of secondary importance. What is important is the recognition that the holding of such inventories depends partly on production and sales--but also partly on carrying costs and the interest charges on the costs invested in bringing each type of inventory to its current state. Thus, even if the supply price was adequate to insure a continual long term flow of gas, it would be rational in a period of rising interest rates for profit-maximizing (cost-minimizing) entrepreneurs to reduce their inventory holdings of all types, and especially those with the greatest invested costs over the longest period of time--i.e., especially proved reserves. In other words, if interest rates rise, it would make good economic sense for producers to reduce reserves relative to production--thus displaying a negative interest elasticity of supply for reserves relative to production.

Except for 1958 and the period 1961 to 1964 when interest rates declined, governmental monetary policy since 1955 has been generally restrictive, forcing up interest rates from their relatively low levels of the mid-fifties to historic highs. The purpose of these tight money policy periods has been to encourage industry to restrain investment spending on plant, equipment, and inventory in order to reduce inflationary pressures in the economy. In the early sixties, besides a deliberate policy of monetary ease, tax policies were adopted (e.g. the 1962 investment tax credit) which were aimed at stimulating investment in the economy. It is not too surprising therefore to find that the generally restrictive monetary policy experienced in recent years had some impact on inventories in the natural gas industry, in that the R/P ratio tended to fall during tight money years. Moreover, the R/P ratio rose in 1958 and was relatively constant in the early sixties when the government was following policies of relative monetary ease and fiscal stimulation. Since 1963 the R/P ratio has declined consistently as governmental anti-inflationary monetary policy was stepped up. If some of the decline in the R/P ratio is the result of anti-inflationary policy, it would be most paradoxical and unfortunate if either Congress or the F.P.C permitted the price of natural gas to consumer to increase substantially in order to encourage an increase in the R/P ratio.

In sum then, it would appear that the decline in the reserve-to-production ratio can at least be partially attributed to the successful result of increasingly restrictive monetary policies which have been adopted in most years since 1955, and hence the trend in the R/P ratio must not be adopted as *prima facie* evidence of a price-induced gas shortage.

Finally, a period of tight money is likely to lead not only to higher interest rates, but also to a shortage of finance. The magnitude of the shortage of finance is not readily quantifiable, but it is likely to lead to credit rationing of externally and internally generated funds which in turn will cause producers to postpone some investment projects. If the government should, in the near future, embark on a monetary policy which brings about lower interest rates and more financing facilities over time, I should suspect, *ceteris paribus*, some increase in the R/P ratio. But in my view the most important factor explaining recent supply behavior of domestic gas and oil producers involves not resource costs, but user costs, that is expectations about future wellhead prices.

B. User Costs and Reserve Offerings. For any particular producer, gas in the ground is a stock or inventory. The more used today, *ceteris paribus*, the less there will be available to sell tomorrow. Consequently, the individual gas producer is faced with the problem of deciding whether to enter into a long term contract to sell his entire inventory at a series of future dates at a price specified today (including escalation)--or to hold off his goods until some time in the future. There is an incentive to delay if he expects the price to be higher in the future. Thus one of the costs as far as the producer is concerned, is the opportunity cost of entering into a contract which sacrifices the present value of expected marginal profits which he gives up by selling some gas today and at future dates at specified prices before an expected increase in the wellhead price. This opportunity cost of potentially lost profits can be labeled the user cost inherent in all raw materials. This cost concept I developed at some length in an article entitled "Public Policy Problems in the Domestic Crude Oil Industry" which appeared in 1963 in the *American Economic Review*. Thus a rational profit-maximizing producer will take this cost into consideration in deciding his sales strategy.

In earlier years, gas producers were partially protected against such costs by "most favored nation clauses" which assured him that if the price rose in the future, the remaining portion of his inventory which still had not been removed from the ground would be sold at the higher price. Nevertheless, he would still have lost the present value of profits on that portion of the gas alread removed from the ground. In more recent times, the F.P.C. has prohibited favored-nations clauses in contracts. At the same time, the course of regulation, including the Statements of General Policy, have given the producers grounds to hope that their ultimately determined rate level might be much higher than the rates at which new sales were being certificated. Thus for example, the possible user cost of sales pending completion of the Southern Louisiana hearings was approximately ten percent to 50 percent of the regulated market price, depending on producer's expectations.

When the Examiner's Decision was handed down in 1967, the producers were obviously disappointed in its results, and again anticipated that the future would bring higher prices than those proposed by the Examiner. The inauguration of a second round of area rate proceedings in the Spring of 1969 kept the expectations high, as does current discussions of de-regulation of all new gas.

As a consequence, this user cost encourages individual producers to restrict the supply of reserves that they offer on the market, and therefore it is reasonable to expect the R/P ratio to fall. Hence, the course of regulation and public policy discussion in recent years has in itself provided some incentive for the decline in the R/P ratio.

The producers obviously anticipate increased prices as a result of the present Congressional proceedings. In the current situation an individual producer with a lease on a field which is yet in an early stage of development, must decide either to commit large sums to develop his field--to "prove reserves"--in order to sell the gas at some early future time, or to speculate on the underground inventory that the price will rise sufficiently to offset the costs of holding the gas a little longer in its undeveloped stage. Moreover, he can minimize carrying costs by keeping the reserves in as low a stage of development as possible. Thus, the opportunity cost of waiting for the F.P.C. to increase ceiling prices or for Congress to de-regulate tomorrow is merely the carrying costs, which can often be limited to the lease acquisition outlays. Offsetting these carrying costs for the producers is the anticipation of the present value of the bonanza of selling gas for 20 years at two, three, or even four times the current regulated price.

In the natural gas market, additions to reserves must be offered for sale on long term forward contracts where future prices and deliveries are specified at the moment the contract is sealed. The willingness of producers to enter into such contracts at any point of time will depend more on expectations of future changes in wellhead prices (user costs) over the life of the contract than in the actual marginal resource cost of developing new reserves; especially if the current wellhead price at least covers the finding and development costs.[5] In such a situation, it is not proper to assume that the marginal resource cost function (R in Figures 1 and 2) is the industry supply function. Rather, expectations about the higher future prices involve positive user costs which must be added to resource costs so that the supply curve (S in Figure 2) will lie above the resource cost curve (R), and as Professor Kahn has suggested in F.P.C. Docket AR61-1 it may even display a negative elasticity as shown in Figure 2.

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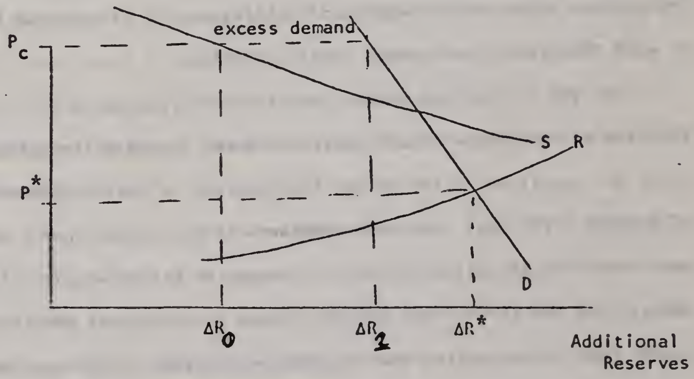
[5] Since then the producer can always sell some reserves and cover costs.

Thus, if P_c is the current wellhead price, then Figure 2 shows (as did Figure 1) that ΔR_o reserves will be forthcoming and that there is an excess demand or shortage of gas in the market at the current wellhead price. But unlike Figure 1, Figure 2 shows that because of the negative supply elasticity any increase in the ceiling price will exacerbate the shortage.[6] What is needed is a policy which would make it

Figure 2



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[6] If, for example, when wellhead prices were raised if this encouraged producers to believe this was only the beginning and if supplies do not cascade forth, the market, susceptible to economic blackmail, would agree to even further raises. Since the demand for gas is inelastic, producers income would rise even if they continued to hold back. (We have an apt analogy of this situation in the current market for OPEC oil.)

unprofitable for producers ever to speculate on future price increases. One such policy is to insist that any increase in the regulated wellhead price is phased in at an annual rate which is less than the current rate of interest, so that the discounted value of the additional profit obtainable from holding reserves off the market in order to sell at expected higher future price is always less than zero. Under such a situation, user costs would be negligible and the marginal resource cost curve would approximate the supply curve and according to Figure 2, a lower P^* would alleviate the shortage.

Speculation and the Energy Shortage. In a world of uncertainty and unregulated markets if there is sufficient number of independent buyers and sellers who have differing views about future prices, there may be no more reason to expect the future price to exceed the current price, than to expect it to decline below current levels. Hence at any point of time, we might assume some producers expect the future price to be lower and others expect it to be higher than the current price, so that the net effect of expectations of future wellhead price on industry supply may be negligible. If, however, events create a situation where all sellers expect rapidly rising prices and moreover in the current regulated environment, ceiling prices are set below what the market could be forced to pay, competitive fuels are controlled by growing monopolies (e.g. OPEC) and/or separate but not independent division of the same "energy companies," where the Congress and the F.P.C. specifically hold public hearings to determine whether the wellhead price should be increased or even decontrolled, each producer can expect, at worse no change in the existing price, and at best a substantial increase. In other words, producer expectations are biased in the direction of some price increase--and hence speculative expectations can have a significant impact on current supply offerings. John Maynard Keynes, once pointed out that economic progress depended on the spirit of enterprise, which, in this context, refers to the activity of producers, motivated by a desire for action rather than inaction and operating under reasonably stable conditions in an uncertain world, to produce a steady flow of output for the economy. Keynes recognized that in an uncertain world, some men's proclivities would always turn to the possibility of making speculative profits via supply manipulations and he noted "Speculators may do no harm as bubbles on a steady stream of enterprise. But the position is serious when enterprise becomes the bubble on a whirlpool of speculation." It is very possible that the current supply situation for natural gas in the U.S. and the cartelized supply of all fossil fuels in the world is in part due to enterprise becoming engulfed in speculative practices. The concept of the user cost inherent in all raw materials provides the insight into understanding how rational gas producers can operate to bring about the current gas supply situation as the result of speculative activities. With the hope of

Growing Monopoly Power and Speculative Successes Reinforce Each Other

In the current energy crisis two major processes have occurred concurrently and these have exacerbated the speculative excesses of the energy market. These processes are (a) the growth of monopoly power of the OPEC cartel and (b) the development of conglomerate multinational energy companies who control substantial quantities of substitute domestic energy supplies.

The impact of the OPEC cartel in recent years is obvious and I need not pursue it at this point. Instead, I shall dwell a few moments on how the growth of conglomerate energy companies has reinforced the ability of the OPEC cartel to raise prices and to create positive user costs in recent years.

The existence of an exploitable monopoly position depends on the present and future price elasticity of demand in the relevant price range. As far as the OPEC cartel is concerned, therefore, it depends in large measure on the current price in consuming countries and ultimately on the supply price at which alternative sources of energy will become significant substitutes for OPEC oil. Suppose, however, the supplier of a substitute energy source also has an economic interest in OPEC petroleum reserves because it is a conglomerate energy company with an OPEC concession or other large oil reserves. Then it will anticipate a positive user cost in providing the substitute if production of this substitute reduces potential profits from its oil reserves. This positive user cost will raise the supply price (above resource costs) or marketing the substitute.

In these circumstances this positive user cost of substitures internalizes a cost that in a competitive economy would be external to an independent producer of a substitute energy source. Independent producers of domestic oil, shale, tar sands, coal, uranium, and so on (provided they were not permitted to share the monopoly returns of the major energy companies), would not care if they inflicted capital losses on the value of foreign underground reserves of petroleum by providing a cheaper energy source. Most reasonable people would argue that society is the beneficiary of a decision to produce a less expensive substitute even though the oil producers and property owners would suffer a capital loss. The existence of rational, multisource, energy-producing conglomerates, however, constrains production of substitute fuels, makes monopolistic control of energy markets easier, and reduces consumer welfare. The ability of conglomerates to maintain high prices for the substitutes tends to reinforce their monopoly power in marketing their OPEC oil.

If at the current price consumer demand for OPEC oil is therefore still in the exploitable range, a strong cartel of oil-producing nations can allow multinational energy conglomerates to continue to raise prices relative to real resource costs. The continuous revenue increases of host nations since 1970 seem to be attempts to search out the point at which demand for OPEC oil becomes so elastic that monopoly rents are fully exploited. (However, for any given demand situation with any degree of elasticity, higher prices require production restrictions, and hence at least tacit market-sharing arrangements to prevent one member of the cartel from increasing its gains at the expense of others.) Since the multinational energy companies also have vested interests in the price of OPEC reserves as long as they retain any monopoly rents, they will be willing tools in maintaining an "orderly" production market in all fossil fuels. Thus monopolistic and speculative withholding reinforce each other and merge into one.

Stopping Speculation

Speculation can be squelched in either of two ways:

(a) adoption of a regulated wellhead price policy which creates an atmosphere of certainty that any future price increases relative to production costs will be at an annual rate so small as to be below annual carrying costs so that it will never pay to speculate on inventories, (e.g., ceiling prices will never increase by more than six percent per annum); or

(b) creation of conditions which make expectations of a future price decline just as likely as an increase, so that individual's speculative expectations tend to cancel. Bluntly, in the current context, this means permitting those who have withheld production in order to profit by it should be so well rewarded by the "free" market that it would appear to many that the consumers no longer have sufficient wealth or income to leave them open to further extortion.

Many people, including President Ford's advisers, believe that decontrolling natural gas and "old" oil wellhead prices would be sufficient to establish the condition (b) above. In present circumstances, however, even decontrol with wellhead prices rising to current cartel levels may not be sufficient to create condition (b).

In the first place history is replete with episodes where "free" or uncontrolled commodity markets have been subjected to disruptive speculative withholdings.

Given that control of significant quantities of alternative fossil fuels are either in the hands of foreign nations or other divisions of the same domestic "energy companies" who are the major producers of oil and natural gas, it may be difficult to create condition (b) as consumers could be continually whip-sawed by price rises in the alternative fossil fuel markets until multinational conglomerate energy producers and OPEC nations believe they have extracted the maximum transfer of income and wealth they can from the impoverished U.S. energy consumers. Even if it were possible, however, condition (b) would probably require, in present circumstances, an immediate and substantial rise in wellhead prices --high enough to convince a sufficient number of producers that the new price exceeded the long run price that the market could bear so that further price movements were more likely to be in a downward direction. Such a price increase would create tremendous economic rents for producers and landowners (which violates any reasonable fairness criterion). It would in essence formally legitimize the existing monopoly control of fossil fuel markets, and it would contribute to our inflationary problem by creating conditions where individual groups of workers and other industries would try to catch up, that is, to re-establish the pre-"energy crisis" purchasing power of their incomes by demanding wage and price increases to offset higher energy prices. Even if were possible to decontrol old oil and natural gas, it would be socially and politically undesirable. Accordingly, we are left with condition (a); to design a policy of regulating the wellhead price in such a way as to eliminate speculation as a factor affecting supply offerings. This will require: (4) regulation of wellhead prices of oil and gas in such a manner as to permit prices to rise relative to costs at an annual rate, which is less than the rate of interest only if such increases are necessary to permit producer to earn a "fair rate of return" and property owners a "fair" payment.

4. If User Costs are Eliminated, What Would be the Regulated Price Which Would Alleviate the Gas Shortage?

As I stated earlier, it is my belief that the major objective of regulation is to obtain an adequate supply at the lowest supply price. If achieved, such an objective will treat both consumers and investors equitably since the latter will be receiving just what is necessary to make it worthwhile for them to undertake the efforts required, while the former receive the product at the lowest price possible without subsidization. The problem, therefore, is for the Commission to:

(a) identify the components of the long-run supply price, and

(b) to quantify these components.

In testimony before the F.P.C. (Docket # AR69-1) I have suggested how such a study could be carried out. I have not done such a study recently and the data I used as a guideline in my F.P.C. testimony is quite old. I would therefore urge the F.P.C. staff to undertake a new study following the principles I have suggested in the aforementioned Docket. If this study showed that current wellhead price was below, or even not very much above the resource costs of adding reserves, then I believe it would be desirable to err on the conservative side and stimulate supply via increasing the wellhead price at an annual rate which does not exceed the rate of interest until it was, say, 10 to 20 percent above this staff's estimate of the marginal resource costs.

Since such a study by the F.P.C. staff will take some time, as an interim measure, I would on the basis of the statistical analysis done in my aforementioned Energy Policy Project permit the regulated wellhead price to rise by two percent per annum and reinstall most favored nation clauses in any new long term contracts entered into during this interim period so that producers would be assured that once they entered into supply contracts the remaining portion of their underground inventories would be sold at the higher prices; and consequently it would never be profitable to hold back reserves in anticipation of speculative windfalls. Such a price increase policy would, according to my analysis, at a minimum prevent any further decline in the overall reserve

PROPOSAL FOR A NATIONAL ENERGY POLICY (NEP)

The sudden quadrupting of the world crude oil price during the 1973-74 period is at least partly responsible for the severity of the current world wide recession and economic dislocations. Moreover, OPEC's future crude oil price policies will remain a serious threat to the survival of the world's monetary relations during the next few years.

In this section I propose to outline a nine point National Energy Policy (NEP) for the United States which will have both short run and longer run implications.

In the short run we should not undertake policies which are likely to exacerbate the current problems of unemployment and inflation. In the longer run, our policies should be oriented towards breaking up the OPEC cartel and the growing monopolistic control of domestic energy sources.

A nine-point National Energy Policy (NEP) which could provide U.S. consumers with sufficient energy while allowing producers to earn a competitive return rather than permitting them to share in cartel profits would include: (1) extensive antitrust action to break up conglomerate energy companies and to create competitive alternative sources of energy (competitive to OPEC sources and the major oil and gas producers), (2) governmental coordination and regulation of wellhead prices of oil and natural gas so that any necessary price increases occur at such low annual rates as to make speculative withholding unprofitable(and in no case should wellhead price of oil and gas be suddenly decontrolled), (3) prohibitive capital gains taxes on oil and gas properties to catch any speculative profits which avoid other policy nets, (4) the changing of leasing policies on federal properties in order to reduce the financial constraint of the front-loaded bonuses and permit independents to develop offshore properties, (5) policies which encourage and require accelerated exploitation of old and new properties, even if in certain situations such policies were to encourage flows in excess of MER, (6) policies which prohibit the "shut-ins" and other practices which permit speculative withholding,[5] (7) an announced increasing schedule of import taxes on foreign crude oil and products over the next three or four years. Such an import tax schedule must be phased in with growing U.S. production while U.S. wellhead prices are controlled as suggested in (2) above, (8) a federal sponsored corporation which at a minimum would aid in financing the development of new properties and might even enter into joint ventures with independents; in other words, a Federal Oil and Gas Corporation (FOGCO); (9) the adoption of the Hart-Church bill (S. 1430) for an import auctioning system with unidentifiable foreign sellers to supply the diminishing share of the U.S. market as we approach self-sufficiency in the next few years is desirable. Such a program will create a positive incentive for members of OPEC to break with the cartel.

In sum, the current energy problems facing the United States and the Free World, in my view, are not due to the niggardliness of nature. Instead, its origins lie in the socially undesirable speculative and monopolistic traits of mankind, and a man-induced shortage of this kind can and must be alleviated by policies that do not pander to such selfish human attitudes.

STATEMENT OF
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CHIEF, PLANNING AND DEVELOPMENT DIVISION
BUREAU OF NATURAL GAS
FEDERAL POWER COMMISSION

HEARINGS BEFORE THE
SUBCOMMITTEE ON ENERGY AND POWER
OF THE
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
U.S. HOUSE OF REPRESENTATIVES

January 27, 1976

LONG TERM PROSPECTS FOR U. S. GAS SUPPLY

I INTRODUCTION

The shortage of natural gas has been a source of surprise, shock and disbelief to most of those affected, but not to many students of long term United States resource development. An eventual shortage of natural gas to meet ever increasing consumer demand has been inevitable. The occurrence of the shortage at this time results from society's rapid and indiscriminate use of the premium, and most limited, finite domestic fossil fuel. The natural gas and petroleum shortages are just two of the melange of resource shortages, both U.S. and world-wide, that scientists and resource analysts have been warning about for years.

Unfortunately, the warnings with respect to natural gas were ignored or misunderstood and we presently find ourselves in a situation in which our realistic expectation for the future is for a steadily declining production capability which will, in all likelihood, respond only modestly to increased price incentives and which cannot be reversed. The fundamental problem facing the Nation today with respect to future natural gas supply is the fact that we are dealing with a resource base which has already been extensively and intensively developed and is rapidly being depleted.

Our present shortage position is additionally accentuated by uncertainty surrounding pricing policy, deficiencies in our leasing programs, a heightened demand for natural gas and the indiscriminate use of gas for inherently inferior purposes. The future decline of domestic conventional supply places increased importance on those supply increments which can be made available from supplemental sources. Gas from these sources, however, will meet only a portion of our future supply deficit. The Nation must pursue policies designed to provide the greatest impetus possible to the simultaneous development of our remaining conventional resources (particularly in the frontier areas) and each of the viable supplemental supply options. In my view, even the most optimistic expectations applicable to anticipated conventional and supplemental supply will still not yield the volumes necessary to maintain present levels of gas availability. For this reason, national policy must also address the need for mandatory conservation, substitution of alternate fuels wherever possible and allocation of available gas to highest priority end uses.

II THE BACKGROUND

Early Warnings of Gas Shortage

Resource specialists have seen the gas and petroleum shortages coming for at least 25 years and, in fact, have predicted the timing and impact of the natural gas shortage with remarkable accuracy. In 1948 the Federal Power Commission concluded a comprehensive investigation of the gas industry (Docket No. G-580). In their report of this investigation Commissioners Leland Olds and Claude L. Draper gave this assessment of future gas supply:

> "The importance of giving the most serious consideration to all aspects of the problem of conserving natural gas is based squarely on the fact that it is a limited and exhaustible resource. Whatever estimates are accepted for the ultimate total of the country's natural gas reserves in relation to ultimate market requirements, it can be asserted without fear of contradiction that at some time in the reasonably near future the deliverability of natural gas is going to begin to decline toward the day when it will no longer be counted among the country's important fuel resources."

The significance of this statement can be appreciated only if one realizes the extremely favorable gas supply situation which then prevailed. In 1948 annual U.S. gas production was 6 trillion cubic feet (Tcf); the total U.S. proved reserve inventory was 173 Tcf, and the Reserves/ Production ratio (R/P) was 29. The R/P ratio is the number of years of supply remaining at the current rate of production without any new reserve additions. New reserve additions in 1948 were more than twice the amount produced in that year. The R/P ratio today is about 11 and 1974 reserve additions were less than half of the amount produced in 1974. In addition to the warning contained in the Docket No. G-580 report, the FPC of that era was voicing concern for gas supply in its pipeline certificate decisions.

A warning similar to that contained in the Olds-Draper report was issued four years later in June 1952 by the President's Material Policy Commission (Paley Commission) which said:

> "Some thought must now be given to the prospect of ultimate exhaustion of natural gas resources in guiding the present development of the industry, as well as to the encouragement of research on the economical production of substitutes from coal or of research into other energy sources such as solar energy to replace gas when the time comes."

The FPC was specifically warned in this passage to keep a tight rein on the expansion of gas markets to prevent demand outrunning supply:

> "It will become increasingly important for the Federal Power Commission, in considering dedicated reserves for a proposed pipeline, to consider the eventual impact of new dedications upon the useful life of existing pipelines, upon the consumers they serve, and upon the long range supply position of communities in the producing area. Excessive building of pipelines and over-commitment of limited reserves could lead, when reserves are gone, to premature obsolescence of costly capital equipment for operators and consumers alike."

Scant attention was paid to these issues until the emergence of the shortage in 1970. During the two decades following the publication of the Paley report the FPC progressively lowered its standards for gas reserve volumes and deliverability capabilities required to support applications for new or enlarged pipeline capacity authorizations.

The Paley Commission also emphasized the importance of eliminating gas waste and conserving natural gas for high priority uses. It specifically served this warning on the FPC:

> "Considering the Nation's limited reserves of natural gas, there is no economic virtue simply in further expanding pipelines, but a clear advantage exists in extending or enlarging access to high advantage users (i.e. high priority users). The problem is not yet one of whether or not to authorize further pipeline construction, but of how much to permit and under what circumstances."

Unfortunately, there was no effective follow-up to the Paley Commission's admonition to start phasing out inferior uses of natural gas. On the contrary, the use of natural gas for electric power plant boiler fuel increased six fold (from 0.6 Tcf to 3.6 Tcf per year) during the 20 years following publication of the report.

The economic dislocations of a gas shortage and the need to develop supplemental gas sources, such as gas from coal, were set forth explicitly by the Paley Commission in these words:

> "At some point beyond 1975, however, more serious problems are likely to arise when natural gas supplies will eventually have shrunk to the point that the general uses in gas producing areas and special uses in all areas are forced to shift to substitute fuels. Costly dislocations may result in the economy of the Southwest, heavy capital costs of conversion will be forced on nearby and distant customers, and the extensive transportation, distribution and utilization systems may be rendered useless. The impact could be reduced if it becomes economic to manufacture gas for at least some of the gas customers, presumably from coal, which could then be distributed through portions of existing transmission and distribution lines, though large segments of such lines would probably no longer be used."

The Paley Commission recommendations are similar in many respects to items on today's FPC gas agenda, i.e. allocation of gas by "end use" categories, problems caused by an excess of pipeline capacity due to a shortage of gas, and economic dislocations.

An interesting aspect of both the Olds-Draper report in 1948 and the Paley Commission report in 1952 is that they each forecast the current gas shortage as an inevitable future event long before the FPC started to regulate the wellhead price of natural gas following the Phillips decision of the Supreme Court in 1954.

In 1962 the National Academy of Sciences examined the Nation's energy resources and published a study by the eminent United States Geological Survey geologist, M. King Hubbert who also saw the approaching shortages of both crude oil and natural gas. Hubbert's 1962 analysis forecast the approximate year in which production of oil and gas in the lower 48 states would peak and then start to decline. For crude oil he put the peak year of production "in the late 1960's or early 1970's". It actually came in 1970. He forecast 1976 as the peak year for natural gas production. He was off by three years for natural gas production which peaked in 1972 or 1973 (production was about equal for these two years) and has declined sharply in 1974 and 1975. Considering the nature of this work Hubbert's production forecasts have been remarkable. They were made at a time when the magnitude of the U.S. Department of Interior's ultimate resource estimates indicated probable increases in U.S. production of crude oil and natural gas well into the 1990's.

It is only fair to point out that energy policymakers during the 1950's and early 1960's were seriously misled by the optimistic forecasts that were being made for the future of nuclear power. They were reluctant to undertake serious oil and gas conservation measures when the conventional wisdom held that cheap, practical and abundant nuclear energy would soon be available to replace any future decline in fossil fuels.

There were, of course, other warnings of a future gas shortage directed at the FPC in formal rate and certificate proceedings. For the most part these came from producers seeking higher gas prices and from the coal interests who sought to prevent the large scale replacement of coal by natural gas and were generally regarded as profit motivated special interest pleadings.

The Present Inadequacy Of Supply

The year 1967 was a significant year for domestic gas supply. Both the total domestic gas supply and the supply dedicated to the interstate pipeline companies reached historic peaks during that year and have exhibited general downward trends ever since. The only interruption to these trends was when the Prudhoe Bay field reserves were added to the total U.S. inventory in 1970.

During 1974, our proved reserve inventory continued to decline and the Nation experienced its first significant decline in natural gas production in the modern history of the gas industry. Production for 1974 in the lower 48 states was down almost 6 percent from the prior year and preliminary data indicate that this decline has continued in 1975 and could be even greater.

The decline in domestic gas supply has been even more evident than our declining domestic crude oil supply because, in the case of gas, the domestic supply gap cannot readily be filled by imports. 1/

Since neither imports nor substitute forms of synthetic gas are available to completely plug the supply gap, the natural gas shortfall increases month by month as domestic production continues to decline. The result is a widespread denial of gas service to prospective new customers, increasing curtailments of firm and interruptible service to existing customers, and the prospect of future dislocations in our economy.

1/ Gas supply for the interstate pipelines is deteriorating at an even faster pace than national gas supply partially because interstate pipelines are being outbid by intrastate buyers in competition for new gas supplies. Interstate reserves have dropped 39 percent from their 1967 peak to year-end of 1974, and interstate production has declined by more than 9 percent since 1972. The decline in reserves and production by FPC pricing areas on a national basis and for the interstate system are shown in Appendix A.

III DRILLING AND DISCOVERY TRENDS

Successful Gas Well Completions

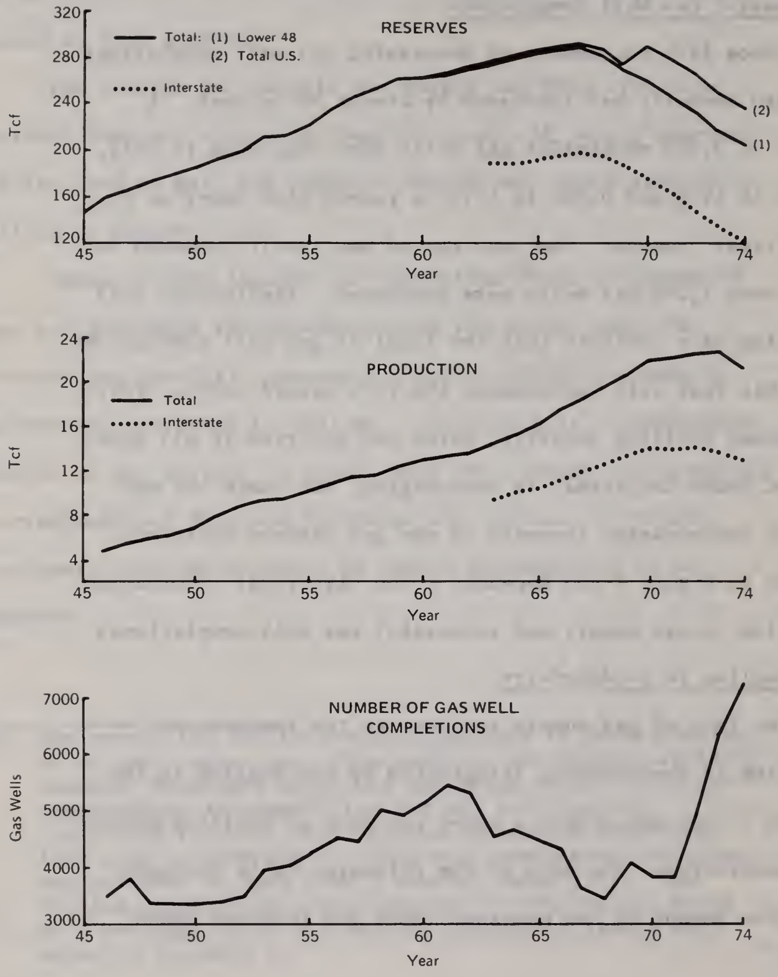
Since 1971 the number of successful gas well completions drilled annually has increased by almost 90 percent. A total of 3,830 successful gas wells were completed in 1971, 4,928 in 1972 and 6,385 in 1973, a record high level up to that time. However, that new record was itself exceeded in 1974 when 7,240 gas wells were completed. Preliminary 1975 drilling data indicate that the level of gas well completions for this year will approximate the 1974 record level. This increased drilling activity, which has occurred in all areas except South Louisiana, is encouraging, but there has not been a commensurate increase in new gas reserve additions. (Refer to Figure 1 and Appendix A for historical information relating to gas supply and successful gas well completions).

The Decline In Productivity

The lack of gas supply response to the increase in drilling is dramatically illustrated by the decline in the amount of new gas reserves added per foot of drilling effort (productivity). The data on the following table indicate that the amount of new non-associated gas reserves added

Figure 1

DOMESTIC GAS SUPPLY



(exclusive of revisions) per foot of successful gas well drilling has been declining particularly since the upswing in drilling activity began in 1972.

Table 1
NON-ASSOCIATED RESERVES
DEVELOPED PER SUCCESSFUL FOOT DRILLED
LOWER 48 STATES

Year	Reserve Additions (Bcf)*	Successful Gas Well Footage (Thousands of Feet)	Productivity (Mcf/Foot)	Percent Change In Productivity
1966	13,079	24,390	536	--
1967	13,571	20,789	653	+21.8
1968	8,298	20,119	412	-36.9
1969	8,315	24,064	346	-16.0
1970	9,641	22,852	422	+22.0
1971	10,037	22,609	444	+ 5.0
1972	9,508	26,743	355	-20.0
1973	9,964	35,587	254	-28.5
1974	8,514	38,975	218	-14.2

* Includes extensions, new field discoveries and new reservoir discoveries but excludes revisions.

This decline in productivity is probably due in large measure to the fact that the increase in drilling activity has occurred primarily in the geologic provinces which have already been the most intensively explored. The probability of finding large fields in these highly drilled areas is smaller than in less well-explored areas because of the finite nature of the natural gas resource base. In effect, the more intensely a geologic province has been drilled, the less gas can be expected to be discovered per future unit of drilling effort.

Table 2 compares gas reserve additions, gas well footage and productivity for selected areas for 1971 and 1974. It may be noted that although productivity has declined in each of the selected areas, the increase in drilling has essentially occurred in the areas characterized by the lowest productivity. About 3.4 million feet (over 20 percent) of the increase in drilling occurred in Appalachia; however, this significant increase in drilling resulted in only a 1.1 percent increase in the area's reserve additions. Appalachia, the oldest domestic producing area, accounted for only 5 percent of the non-associated reserve additions in 1974. The rest of the drilling increase, 13.3 million feet (about 80 percent) took place in the "Other" traditional onshore area (Column 4), but resulted in only a 34 percent increase over the relatively low 1971 level of reserve additions. Productivity for the "Other" traditional onshore areas also

Table 2

COMPARISON OF 1971 AND 1974 GAS RESERVE ADDITION, GAS WELL FOOTAGE AND PRODUCTIVITY DATA BY SELECTED AREA

	South Louisiana Offshore 1/ (1)	Texas R.R. District 8 (2)	Appalachia (3)	Other 2/ (4)	Lower 48 States Onshore 3/ (3) + (4) (5)	Lower 48 States Total (6)
Non-Associated Reserve Additions (Bcf) 4/						
1971	3,882	1,377	405	4,373	4,778	10,037
1974	1,613	603	435	5,863	6,298	8,514
Increase or (Decrease)	(2,269)	(774)	30	1,490	1,520	(1,523)
Percent of Total						
1971	38.7	13.7	4.0	43.6	47.6	100.0
1974	18.9	7.1	5.1	68.9	74.0	100.0
Increase or (Decrease)	(19.8)	(6.6)	1.1	34.1	26.4	--
Successful Gas Well Footage (1,000')						
1971	2,057	1,304	5,200	14,048	19,248	22,609
1974	1,568	1,529	8,576	27,302	35,878	38,975
Increase or (Decrease)	(489)	225	3,376	13,254	16,630	16,366
Percent of Total						
1971	9.1	5.8	23.0	62.1	85.1	100.0
1974	4.0	3.9	22.0	70.0	92.0	100.0
Increase or (Decrease)	(5.1)	(1.9)	(1.0)	7.9	6.9	--
Productivity (Mcf/Foot) 5/						
1971	1,887	1,056	78	311	248	444
1974	1,029	394	51	215	176	218
Increase or (Decrease)	(858)	(662)	(27)	(96)	(72)	(226)

1/ Gas reserve additions for Zones 2, 3 and 4; gas well footage for Zones 1, 2, 3 and 4.

2/ Other includes Texas Gulf Coast, Hugoton-Anadarko, Other Southwest, Rocky Mountain, Permian Basin exclusive of District 8, and the All Other miscellaneous area.

3/ Same as total lower 48 states, exclusive of South Louisiana Offshore and Texas Railroad District 8.

4/ Includes extensions, new field discoveries and new reservoir discoveries but excludes revisions.

5/ Non-associated gas reserve additions (excluding revisions) divided by successful gas well footage.

Sources: Reserve additions - AGA; gas well footage - API.

declined over 30 percent from 311 Mcf per foot in 1971 to 215 Mcf per foot in 1974.

If drilling continues to be concentrated in these well-explored areas the productivity factor will continue to decline unless operators become more selective in their choice of prospects to drill. Although this would result in a higher productivity factor, it would undoubtedly result in even less reserve additions. Probably the only way to significantly increase reserve additions would be to shift the emphasis on gas well drilling to areas where the productivity factor has been historically high, or to the frontier areas which may contain large undiscovered fields. Two traditional producing areas that have relatively high productivity factors are the South Louisiana offshore area and the deep portion of the Permian Basin (Texas Railroad Commission District 8). However, as can be noted on Table 2 the productivity factor for both of these areas declined precipitously from 1971 to 1974. This indicates that even in these prolific areas new large fields are becoming more difficult to find as these areas become more well-developed.

Reserve Additions Misleading

The emergence of the gas shortage in 1970 requires some explanation. The question may well be asked why Federal policymakers and gas industry leaders did not take steps to curb the expansion of gas markets and the Nation's dependency on natural gas. From the AGA reserve addition data shown on Table 1 in Appendix A it can be seen that in each year prior to 1968 reserve additions exceeded production, and as a result, the total U.S. proved gas reserve inventory increased each year. This fact was frequently cited when questions were raised about the prospects for long term U.S. gas supply. There was no cause for alarm, it was thought, as long as annual reserve additions exceeded production withdrawals. It now appears that there were other important aspects of these reserve addition figures as well as other factors which should have been examined more closely.

One of these factors was that a fairly high level of reserve additions can be maintained for a long time through continued development of previously discovered fields. For example, reserves relating to discoveries made prior to 1967 increased 45 Tcf from the end of 1966 through 1974. Excluding the Prudhoe Bay field, these additions accounted for about one half of the 90 Tcf of new reserves added during the eight year period. Over 5 Tcf of the 90 Tcf added to the reserve inventory resulted from upward revisions to reserves discovered in 1922 and prior years. Although large fields are still being discovered they are not of the same caliber as some of the earlier discoveries that still are an important part of the proved domestic gas supply.

Importance Of Large Fields

The natural gas industry depends primarily upon the production of gas from a relatively few large fields. Of the more than 6,000 gas producing fields in the U.S., approximately 100 large fields, or less than 2 percent of the total, contain over 50 percent of the domestic gas reserves and provide a substantial portion of the gas production.

The fact that the natural gas industry relies so heavily on a few large fields is not a problem in itself. The difficulty arises from the fact that the majority of the large fields are old fields. As an example, out of the 15 largest interstate fields which contain almost 30 percent of the interstate reserves, 11 were discovered prior to 1960 with the remaining 4 being discovered between 1960 and 1963. Four out of the 5 largest were discovered prior to 1940, with the largest being discovered in 1922. These large fields through the years have provided much of the deliverability of natural gas for both the interstate pipeline systems and the total industry.

An analysis based on data from the National Gas Reserve Study (NGRS) also indicates the importance of the "old" fields to our national gas supply. This analysis shows that one half of the 108 largest gas fields in the U.S., at the end of 1970, was discovered before 1950. Although data are not available to update this analysis, information relating to the 50 largest gas fields at the end of 1974 indicates that there has been little change in the situation.

There is additional evidence that the frequency of finding large or "significant" fields is declining. Information developed by the American Association of Petroleum Geologists (AAPG) shows a downward trend in the number of significant gas fields being discovered. The AAPG classifies new field discoveries by size after examining six years of development history. They define as "significant" any gas field containing more than 6 billion cubic feet of ultimately recoverable proved reserves. The significant fields are further subdivided into the following four categories:

Class A-Fields	Over 300 billion cubic feet of gas
Class B-Fields	150 to 300 billion cubic feet of gas
Class C-Fields	60 to 150 billion cubic feet of gas
Class D-Fields	6 to 60 billion cubic feet of gas

The AAPG's data show a decline in both total significant fields and in fields in the "A" category. This latter category is particularly important because it would include giant fields (over 1 Tcf) that might be discovered. The number of significant gas field discoveries declined from 99 in 1957 to 40 in 1968, the last year for which six years of development history is available. There were 9 "A" field discoveries in 1957 which was exceeded only in 1951 and 1952 when 10 Class "A" fields were discovered. The following table lists total significant discoveries, "A" field discoveries and the gas reserves discovered during the 1957-1968 period.

Table 3

"SIGNIFICANT" GAS FIELD DISCOVERIES BY YEAR (1957-1968)

Year	Number of Significant Gas Field Discoveries Total Fields	A-Fields	Gas Reserves By Year of Discovery (Tcf)
1957	99	9	15.8
1958	73	3	18.5
1959	62	4	11.0
1960	80	6	11.9
1961	46	4	10.5
1962	79	3	12.0
1963	50	4	12.3
1964	53	4	9.3
1965	52	1	7.7
1966	47	1	7.0
1967	41	4	5.3
1968	40	1	6.4*

*Excludes the 26 Tcf discovered in the Prudhoe Bay field.

Preliminary information now available from AAPG indicates that the number of significant field discoveries will continue to decline through 1974.

The sharp decline in the discovery of significant gas fields starting in the 1950's may have been the initial indication that the easier to find portion of our natural gas resource base had been discovered. However, the approach of the current gas shortage was masked by the fairly satisfactory level of annual reserve additions through 1967, sustained in large part by the continued development of previously discovered fields.

The decline in the number of significant gas field discoveries since 1957 and the close relationship of this decline with ultimate reserves for all fields discovered grouped by year of discovery are shown on Figure 2.

The Declining Discovery Rate

Another highly revealing statistical relationship is the 30 year gas discovery rate derived by dividing each year's total wildcat exploratory footage into the ultimate volume of new gas supply discovered each year. 2/ Wildcat wells are those aimed at the discovery of new fields. In 1947 the average foot of wildcat exploratory hole resulted in the discovery of more than 800 Mcf of gas but since then the average discovery rate has constantly declined. (See Figure 3).

In two important respects the decline in the discovery rate has actually been worse than the data suggest. During the years prior to 1960 the search was directed primarily to oil, and the gas discoveries were in large measure incidental

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2/ The discovery estimates used are from the AGA's Ultimate Recovery of Natural Gas by Year of Discovery series. This is a dynamic series where the annual estimates change each year as they are adjusted to account for additions, revisions and new reservoir discoveries. Because the reserves found in the most recent years are still undergoing development, that portion of the curve representing the last five or six years is conservative and will require modification as additional data become available in the future.

Figure 2

COMPARISON OF SIGNIFICANT DISCOVERIES AND ULTIMATE GAS RESERVES BY YEAR OF DISCOVERY

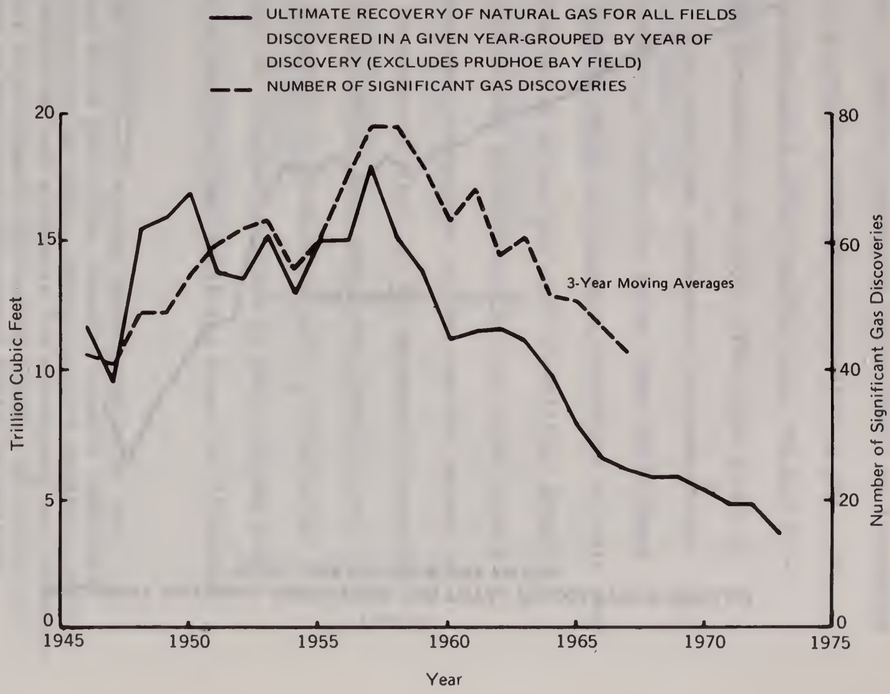
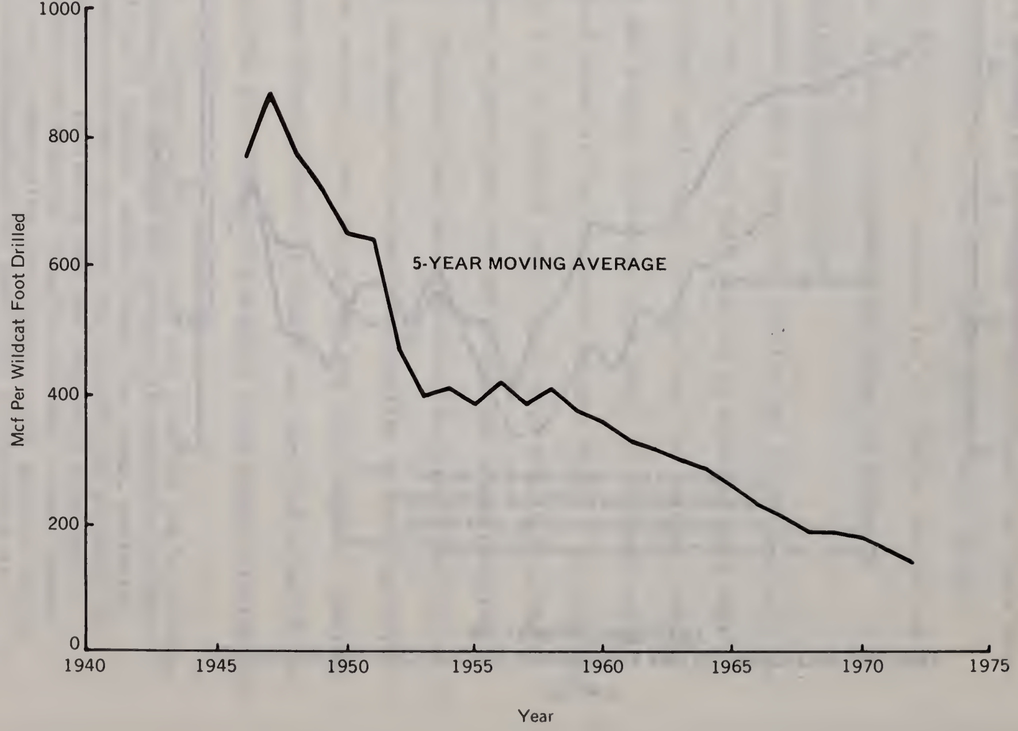


Figure 3

DISCOVERY RATE-MCF DISCOVERED PER TOTAL WILDCAT FOOT DRILLED
(EXCLUDES PRUDHOE BAY FIELD)



to that search. Starting during the early 1960's an increasing portion of the search was directed toward finding gas. Yet, even with this purposeful effort to find gas, the gas discovery rate has continued to decline. The other point is that although there have been continuous improvements in exploration technology during the years since 1945, these improvements have not been sufficient to stabilize or halt the decline in discoveries of gas per unit of drilling effort.

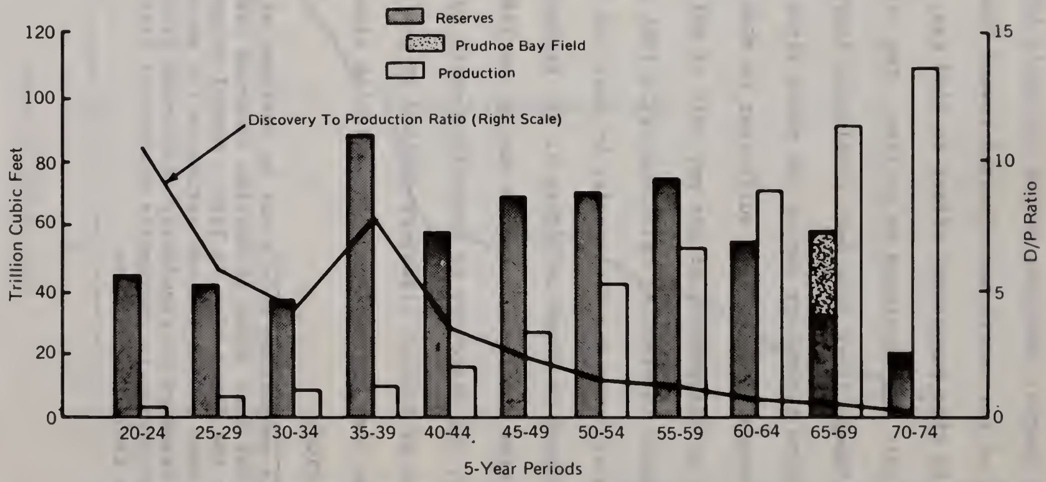
Another interesting relationship is that which exists between ultimate gas discoveries by year and the amount of gas produced as shown on Figure 4. 3/ Production exceeded discoveries for the first time during the 1960-1964 period. However, the discovery to production ratio (ultimate gas reserves by year of discovery divided by gas produced over the same time period) has been declining since the 1935-1939 time period.

3/ This comparison should not be confused with the data series that shows production exceeded reserve additions for the first time in 1968. Annual reserve additions used in that series include estimates for extensions and revisions to reserves in previously discovered fields, new reservoir discoveries in previously discovered fields as well as new field discoveries.

Figure 4

ULTIMATE GAS RESERVES BY YEAR OF DISCOVERY VS. ANNUAL GAS PRODUCTION*
5-YEAR PERIODS (1920-1974)

Total Gas Discovered (12-31-74)=713 Tcf
Cumulative Production =480 Tcf
Remaining Proved Reserves =237 Tcf **
**Includes 4 Tcf in Underground Storage



*See Footnote 2, page 22.

Ultimate Natural Gas Resource Base

The primary constraint on prospects for future gas supply is the finite nature of the natural gas resource base. Many estimates of the domestic natural gas resource base have been made in the past based on varying criteria and methodologies. Until recently these estimates varied widely in magnitude. The most current estimates are in general far lower and compare more closely than the previous estimates.

The ultimate resource base is composed of all the natural gas that has been found to date and includes cumulative production, proved reserves and probable (or inferred) reserves plus undiscovered resources. Some estimators consider only undiscovered resources while others including the Potential Gas Committee (PGC) and the United States Geological Survey (USGS), also make estimates of the probable, or inferred reserves. These latter reserves are in part already discovered and are defined by the USGS as reserves in addition to demonstrated (proved) reserves that will eventually be added to known fields through extensions, revisions and new pays (reservoirs). Inferred reserve estimates range from 202 to 266 Tcf as estimated by the USGS and the PGC, respectively.

Table 4 contains a comparison of some of the most recent estimates of domestic undiscovered natural gas resources. In order to make the various estimates comparable, the probable or inferred reserves have been excluded from the USGS and PGC estimates. With the exception of the 1974 USGS estimates, which are included to illustrate the change in thinking of the USGS regarding the magnitude of the undiscovered gas resource, the estimates range from 322 to 880 Tcf. It may be noted that, with the exception of the PGC estimate, all of those estimates fall within the range of 322 to 655 Tcf set forth in the 1975 USGS estimate.

These estimates indicate quantitatively where the Nation presently stands with respect to the exploitation of its ultimate natural gas resource base and provide a rough idea of the level of gas discoveries that we can expect in the future. Table 5, which utilizes the USGS estimates because they indicate a range, relates the gas reserves which have been discovered since the start of the oil and gas industry and the current USGS estimates of gas resources yet to be discovered.

Table 4

RECENT ESTIMATES OF UNDISCOVERED NATURAL GAS RESOURCES 1/
(Volumes in Trillion Cubic Feet)

Area	PGC 1/,2/	Moody 3/	Hubbert 4/	NAS 5/	USGS 1/ 9/	USGS 1/,6/
Lower 48 States	568	234	281	-	724-1450	286-529
Alaska	312	209	80	-	275-550	29-132
Total U. S.	880	443	361	530	1,000-2,000	322-655 7/,8/
Date of Release	1973	1974	1974	1975	1974	1975

1/ Excludes probable and inferred reserves.

2/ Potential Gas Committee. Probable reserves estimated at 266 Tcf.

3/ John D. Moody, former Mobil Oil Company Senior Vice President for exploration and production.

4/ M. King Hubbert, USGS. (Personal estimate; United States Geological Survey Circular 725, p. 47).

5/ National Research Council of the National Academy of Sciences.

6/ United States Geological Survey Circular 725. Inferred reserves estimated at 202 Tcf.

7/ That portion of the resource base judged to be discoverable and recoverable within the limits of 95% and 5% probability. The USGS estimates that the probability of finding 322 Tcf is 95% compared to only 5% probability of finding 655 Tcf.

8/ Totals for the low and high values are not obtained by arithmetic summation; they are derived by statistical methods.

9/ United States Geological Survey, News Release (March 26, 1974). Inferred reserves estimated to be from 130-250 Tcf.

Table 5
ULTIMATE NATURAL GAS RESOURCE BASE
(Volumes in Trillion Cubic Feet)

	Discovered Reserves*	Undiscovered Resources	Ultimate Resource Base	Discovered Reserves As a % Of Ultimate Resource Base
Lower 48 States	867	286 - 529	1153-1396	75 - 62
Alaska	48	29 - 132	77-180	62 - 27
Total U.S.	915	322 - 655	1237-1570	74 - 58

*Includes cumulative production, proved reserves and inferred reserves.

It may be observed from the table that if it is assumed that the low range of the USGS undiscovered resource estimate is correct, then three-quarters of our ultimate resource base has already been discovered. If the higher end of the range is used, then about 60 percent of our ultimate natural gas resource has been discovered. In any event, with the possible exception of Alaska, and the Atlantic and Pacific Outer Continental Shelf areas where little or no exploration has occurred, the majority of our large fields have probably already been found. Additionally, there is a growing concern among government and industry geologists that the Gulf of Mexico area is apparently running out of first class oil and gas prospects. This area had been expected to play an increasingly important role in meeting our future gas supply requirements, and it has provided about 40 percent of the lower 48 states reserve additions from 1970 through 1974.

Responses to the more recent lease sales are indicative of the increasing pessimism on the part of industry experts. Prior to 1974 over 62 percent of the acreage offered in the Gulf of Mexico OCS wildcat lease sales was leased. Beginning in 1974 this percentage has been less than 50 percent, and, for the first three lease sales held in 1975, only 23 percent of the 6 million acres offered were actually leased. Average bid prices per acre for three Gulf of Mexico wildcat lease sales in 1974 were $4,967, $2,605 and $2,248. Average per acre bids for three similar lease sales in 1975 were only $438, $572 and $485.

Thus, despite a very high level of successful gas well drilling today, the results have been disappointing in terms of total new gas supply. New discoveries have been small with few major new gas provinces opened for future development.

IV OUTLOOK FOR FUTURE GAS SUPPLY

The gas shortage which began in 1970 has impacted heavily on certain gas consumers and has been marked by acrimonious public debate, some of it centering on the role of the FPC. During this period, many industrial gas users shifted their operations to alternate fuels and reduced their dependency on natural gas. Ironically, one of the causes of the gas shortage - widespread use of natural gas for boiler fuel and other low priority uses - has made it easier for State and Federal authorities to protect the gas supply of home owners, small businesses, and other essential industrial users who specifically require natural gas. Through various curtailment priority plans, State and Federal regulatory agencies have thus far been able to assign most of the natural gas deficit to date to boiler fuel and other low priority uses. With the help of warmer-than-normal winter weather, the Nation has on the whole adjusted more or less smoothly to declining natural gas supplies. However, as supplies continue to shrink in the future, the shortage will be more difficult to manage as curtailments move up the priority ladder.

Curtailments of interstate natural gas at the wholesale level as reported to the FPC are now running at an annual rate of about 22 percent of requirements for firm service and 66 percent of requirements for interruptible service. Curtailments are expected to be higher during the current heating season than for the same period last winter and to continue to worsen for the indefinite future.

Future Production Availability

Gas production had increased at an annual rate of about 7 percent for more than 25 years until 1970 when the growth curve flattened out. Between 1970 and 1973, production increased only slightly followed by the sharp decline in 1974 when production declined significantly for the first time. Preliminary 1975 gas production data indicate that production will again decline at about the 1974 rate. Our analyses and studies indicate that this sharp two year decline in production after so many years of growth is primarily the result of declining productive capability. However, energy conservation, warmer-than-normal weather, and the current economic recession may have had some effect on production.

Our analysis of historical natural gas reserve additions and prospects for future reserve additions indicates that annual production will continue to decline, even assuming successful exploration and development of the frontier areas. Figure 5 depicts historical gas production for the years 1960 through 1974 and displays projections of future conventional natural gas production through 1985, including new production from the frontier areas.

The projection of productive capability for the lower 48 states' traditional gas producing areas (Curve (1) on Figure 5), is based on average reserve additions of 9.3 Tcf per year for a total of 102.3 Tcf of reserves added during the 11 year period. This level of reserve additions is equal to the average experienced in the lower 48 states during the 1968-1974 period. 4/ We believe that this is a reasonable but optimistic level of reserve additions to expect from our traditional gas supply areas over the next 11 years.

Curve (2) on Figure 5 shows projected production levels for gas from traditional lower 48 state producing areas plus onshore Alaskan gas (primarily gas from Prudhoe Bay and the Cook Inlet area). Curves (3) and (4) include possible new

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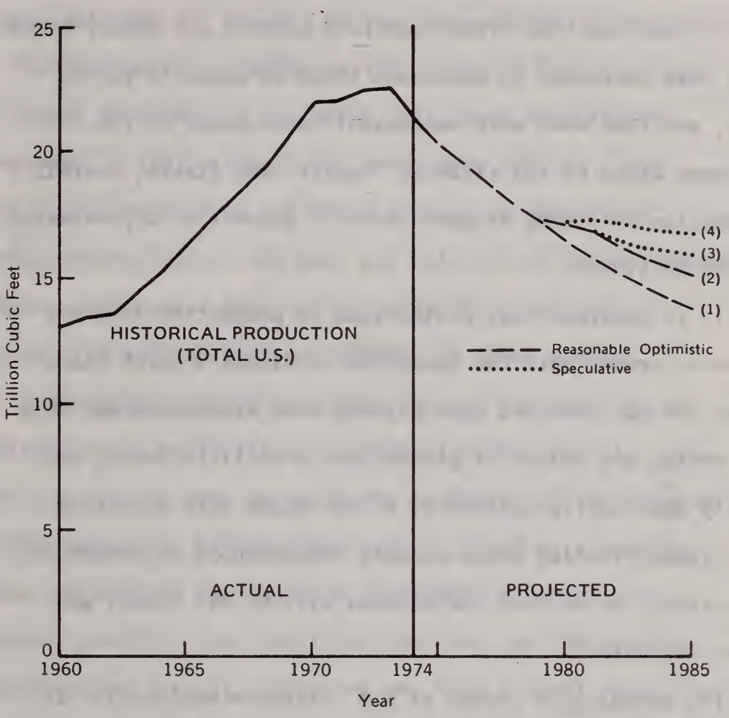
4/ Federal Power Commission, Bureau of Natural Gas. "A Realistic View of U.S. Natural Gas Supply," December 1974, p. 12. In this publication projections of gas production were based on the 1968-1973 reserve addition average of 9.5 Tcf.

Figure 5

PROJECTED PRODUCTIVE CAPABILITY
TOTAL U.S. CONVENTIONAL GAS SUPPLY



Basis for Projections

(1) Reserve additions of 9.3 Tcf (1968-1974 Average)*
(2) Curve 1 plus onshore Alaska and the Cook Inlet Area.
(3) Curve 2 plus the Alaskan OCS.
(4) Curve 3 plus the Atlantic and Pacific OCS.

*Lower 48 states onshore plus the Gulf of Mexico and the Santa Barbara Channel.

production from the Atlantic, Pacific and Alaskan Outer Continental Shelf (OCS) areas. Curves (1) and (2) are regarded as reasonable but optimistic.

We conclude that production from present gas supply areas will have decreased by about one third to about 14 Tcf by 1985, and that even with successful development of the offshore areas of the Atlantic, Pacific and Alaska, overall production will have dropped about 20 percent to approximately 17 Tcf by 1985.

It is apparent that projections of production from the frontier areas, with the exception of Alaska's North Slope where the gas reserves have already been discovered and only the timing and volume of production is still in doubt, are highly speculative because it is not known with certainty that these frontier areas contain hydrocarbons in commercial quantities, or whether these areas will be oil prone, gas prone, or both.

The speculative nature of U.S. offshore exploration is clearly indicated by the historical record. For example, exploratory drilling on leases purchased in two previous major offshore lease sales, the Washington-Oregon lease sale of October 1964 and the Mississippi, Alabama and Florida (MAFLA) sale of December 1973, has resulted in no commercial discoveries of oil or gas. Twelve unsuccessful exploratory test wells were drilled on acreage leased in the Washington-Oregon sale and all of this acreage was eventually released to the government. Similar drilling results have occurred on leases purchased in the MAFLA sale where drilling was suspended in 1975 after 15 dry holes were drilled. The lack of discoveries on the MAFLA acreage is especially disappointing because the area was believed to have a significant undiscovered hydrocarbon potential as evidenced by the $1.5 billion paid by industry in lease bonuses.

Additionally, there are other factors that affect the reliability of projections of production from frontier areas such as, (a) the rate at which the industry will be capable of processing the acreage that may be leased as a result of sales included in the Interior Department's current lease schedule, and (b) the likelihood that the lag time between discovery and initial production may vary several years from one frontier area to another.

The production projections for these areas, with the exception of Alaska's North Slope gas which is projected to start flowing in 1980 at about 1 Tcf per year, were based on the Interior Department's current accelerated leasing schedule which extends through 1978. We doubt that this proposed leasing program can be carried out as scheduled, however, because of environmental and other considerations. The schedule as presently proposed includes 9 sales in Alaska's offshore waters, 6 in the Atlantic OCS and 3 for the Pacific OCS. 5/ The timely offering and successful development of these leases as well as the timely development of the required transportation systems is necessary if our projected levels of production are to be attained.

The details of our production and reserve projections for the frontier areas (the Atlantic and Pacific OCS and Alaska) are shown on Tables 1 and 2, Appendix B.

Supplemental Gas Supplies

There are several sources of supplemental gas which can help to offset the anticipated decline in conventional natural gas supply. The most significant of these in the 1975-85 time-frame appear to be pipeline imports from Canada,

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5/ The first of these sales was held on December 11, 1975 for tracts in the Southern California OCS. Only 56 out of a total of 231 tracts offered were leased for a total bonus of $417 million.

liquefied natural gas (LNG) imports, coal gasification, substitute natural gas (SNG) produced from liquid hydrocarbons, and the stimulation of low-permeability natural gas reservoirs.

The most recent in-depth Commission analysis of the potential availability of gas from these sources was done during 1973 as a part of the National Gas Survey. Since that time, however, the outlook for the availability of gas from these sources by 1985 has deteriorated. The qualitative discussion of each of the supplemental sources which follows recognizes the intervening pertinent developments with respect to these supplemental sources. Our observations here are not the result of a complete re-evaluation of the outlook for each supplemental source. It is anticipated that studies currently being developed as a part of the continuing National Gas Survey work will provide further detailed estimates of the projected availability of supplemental gas supplies.

The following table shows the range of 1985 supplemental gas supply volumes as projected in the 1973 National Gas Survey:

Table 6

1985 SUPPLEMENTAL
GAS SUPPLIES
(Tcf)

Source	Low Estimate	High Estimate
Pipeline Imports	0.9	2.9
LNG Imports	0.4	3.8
Gas from Coal	0.7	1.9
SNG from Liquids	0.9	2.8
Tight Reservoir Gas	0.0	3.0
Total Supplemental Gas	2.9	14.4

During 1974 Canada cut pipeline imports to the U.S. by about seven percent to 0.9 Tcf and drastically escalated the price. Current indications are that Canadian imports in 1975 will approximate the 1974 level. The low estimate for pipeline imports on the above table assumed that all authorized volumes would be imported. However, the Canadian National Energy Board (NEB) has recently made public its intention to limit exports to those volumes in excess of Canada's projected needs. Based on a recent NEB forecast of annual deliverability of Canadian gas reserves and a "medium" projection of gas demand, it now appears that there might be no gas available for export by 1985. The NEB forecasts are shown on Table 3, Appendix B.

Proposed LNG import projects have also suffered numerous delays and several of the projects which had been filed with the Commission have been subject to significantly higher renegotiated prices. In addition, while there has been public reference to further projects beyond those filed with the Commission, several of the apparently most solid prospective projects have been cancelled without indication of new projects to replace them.

The projects which have been filed with the FPC are shown on Table 4, Appendix B. If all of these projects are approved and reach full operational capacity by 1985, about 1.5 Tcf of LNG would be imported. To date only two of these projects have been approved by the Commission and, in these cases, the related proceedings have been reopened for further consideration. The other projects listed on Table 4 have encountered delays due to environmental, financing, and supply pricing considerations, among others. It is also significant to note that no new import projects have been added to this list since 1973. Achievement of a level of even 3 Tcf per year of LNG by 1985 would require optimum timing in the development of the currently filed projects, plus development of an equivalent number of projects yet to be filed with the Commission. At the present time attainment of 3 Tcf per year from LNG should be considered a "very optimistic" possibility.

Movement toward development of a commerical coal gasification industry has not been as rapid as had been expected. This has been due primarily to the unexpected levels to which projected costs, associated with both current and future processes for coal gasification, have escalated. The capital intensity inherent in these developing technologies, investor uncertainty over inflation, high interest rates, governmental energy policies, and, in the case of gas producing technologies, lack of FPC jurisdiction, have combined to significantly slow the rate of progress originally anticipated in this area. The regulatory processes required under the law by numerous Federal, State and local agencies have also proved to be very complex, time consuming procedures.

A number of plants have been constructed or are planned which will produce SNG from light liquid hydrocarbons such as naphtha, and a few facilities are planned using crude oil for feedstock. However, the current volatility of the price and availability of the required liquid feedstocks, mostly imported, as well as Federal regulations on the use of certain refined petroleum products as SNG feedstocks, have caused plans for many proposed SNG-from-liquids plants to be shelved. The outlook for significant impacts on gas supply from this source is considerably less optimistic than it once was.

Nuclear explosive fracturing is not now considered to be a commercially feasible alternative within the 1975-85 time-frame for the stimulation of low-permeability gas reservoirs or formations. Thus, massive hydraulic fracturing techniques are the only methods currently thought feasible for development. The rate of development of this technology has not kept pace with projected progress and is at best now considered to be two to five years behind schedule.

Of the five supplemental gas sources which appeared most promising two years ago, all are experiencing serious difficulties or delays today. Thus, our previously "most pessimistic" 1985 projections of supplemental gas supplies may now well be "optimistic."

V CONCLUSIONS

The decline in available natural gas supplies, which we are experiencing at present, is an event which prestigious authorities warned us about twenty-five years ago. Unfortunately, the warning was ignored by the government, by the industry, and by the public. Discussions of our current gas supply problems have now largely degenerated into attempts to fix blame, on the one hand, and to demands for massive wellhead price increases, on the other hand. But it is fruitless to try to pinpoint responsibility for the gas shortage when society as a whole is responsible for and has enjoyed the results of the exploitation of this limited, finite natural resource. And, if our analyses concerning characteristics of the resource base and future productive capability are correct, then we cannot expect price increases to provide the solution to declining gas production. While increased price incentives might ameliorate the situation somewhat, our policies should be based on the expectation of decreasing gas availability.

There are a number of factors that may be accentuating the gas shortage, such as uncertainty concerning wellhead price, demand for gas to solve air pollution problems, deficiencies in the offshore leasing program, and the profligate use of gas in certain areas for low priority purposes. Yet the basic underlying cause of the gas shortage is the simple fact that the Nation is running short of economically recoverable gas resources that can be readily converted to producible reserves. Nature required several hundred million years to create the natural gas resource below the 48 states, but only three generations of Americans will have burned up 80 percent of this rich heritage within less than 100 years. 6/

Supplementary gas sources such as gas from coal, imported liquefied natural gas, and pipeline imports from the far north, are encountering serious delays and difficulties and will meet only a portion of the future natural gas deficit. Gas from these sources will be expensive and slow to reach markets. Even so, these supplementary gas sources must be pursued vigorously. The Nation's frontier areas--the Atlantic and Pacific Outer Continental Shelf and Alaska--are believed

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6/ "U.S. Energy Resources - A Review as of 1972", A National Fuels and Energy Policy Study for Interior and Insular Affairs Committee of U.S. Senate (Serial No. 93-40 (92-75)), p. 148.

to have the potential for significant future discoveries and their exploration should be given a high priority. The frontier areas and supplemental gas sources, however, will provide only a limited supply of gas, and, if we have learned anything at all from our experiences of the past, other important programs of national energy policy must also include mandatory natural gas conservation, substitution of alternate fuels for low priority uses of gas, and the allocation of scarce gas supplies by Federal, State and local jurisdictions to high priority end uses.

APPENDIX A

The attached series of tables and figures traces the development of domestic natural gas supply on both a national and regional level. The tables include two sets of reserve and production data. The first set of data on each table is based on American Gas Association statistics and relates to the total gas supply. The second set of data is based on FPC Form 15 information and includes only interstate gas supply statistics. The tables are accompanied by figures which graphically display the reserves and production data plus the available successful gas well completion information.

By the end of 1974 all of the gas supply areas except Alaska, Appalachia and the Louisiana Offshore Federal Domain exhibited declining total reserves trends, although the latter area's total reserves peaked in 1970. Total reserves reached peak levels in the other areas ranging from 1958 for the Rocky Mountains to 1968 for South Louisiana. The interstate reserves trends, in general, closely parallel the total reserves trends for the various areas with the exception of Appalachia where the interstate reserves have been declining since 1964.

Total production continued to increase into the early seventies in most of the areas. By the end of 1974, however, only the Permian Basin and the Louisiana Offshore Federal Domain areas were still exhibiting increasing production trends. Interstate production trends are similar to the total production trends in the important supply areas except for the Permian Basin area where interstate production reached a peak in 1971.

Successful gas well completions in 1974 were significantly higher than in 1970 for all areas except the important South Louisiana gas producing area. However, with the exception of the All Other area, this recent increase in successful gas well drilling has yet to impact the gas reserve inventory.

Table 1

TOTAL UNITED STATES 1/,2/
(VOLUMES IN TRILLIONS OF CUBIC FEET)

SOURCE: AGA

YR	PROD	RESERVES	GROSS R.A.	REVISIONS	NET R.A.	R/P RATIO
45	N.A.	146.986723	N.A.	N.A.	N.A.	N.A.
46	4.915774	159.703813	N.A.	N.A.	17.632864	32.5
47	5.599235	165.025765	N.A.	N.A.	10.921187	29.5
48	5.975001	172.925056	N.A.	N.A.	13.823090	28.9
49	6.211124	179.401693	N.A.	N.A.	12.605615	28.9
50	6.855244	184.584745	N.A.	N.A.	11.985361	26.9
51	7.923673	192.758910	N.A.	N.A.	15.965808	24.3
52	8.592716	198.631566	N.A.	N.A.	14.267606	23.1
53	9.188365	210.298763	N.A.	N.A.	20.341933	22.9
54	9.375314	210.560931	N.A.	N.A.	9.547074	22.5
55	10.063167	222.482544	N.A.	N.A.	21.897610	22.1
56	10.848686	236.483215	N.A.	N.A.	24.716115	21.8
57	11.439891	245.230138	N.A.	N.A.	20.008056	21.4
58	11.422651	252.761790	N.A.	N.A.	18.896717	22.1
59	12.373064	261.170431	N.A.	N.A.	20.621254	21.1
60	13.019357	262.326330	N.A.	N.A.	13.893980	20.1
61	13.378650	266.273641	N.A.	N.A.	17.166421	19.9
62	13.637973	272.278782	N.A.	N.A.	19.483956	20.0
63	14.546025	276.151233	N.A.	N.A.	18.164668	19.0
64	15.347028	281.251454	N.A.	N.A.	20.252138	18.3
65	16.252293	286.468923	N.A.	N.A.	21.319279	17.6
66	17.491073	289.332805	15.282470	4.937962	20.220432	16.5
67	18.380838	292.907703	15.233755	6.570578	21.804333	15.9
68	19.373428	287.349852	10.680862	3.016146	13.697008	14.8
69	20.723190	275.108835	9.613265	-1.238261	8.375004	13.3
70	21.960804	290.746408	37.296080	-0.099721	37.196359	13.2
71	22.076512	278.805618	11.052821	-1.227400	9.825421	12.6
72	22.511898	266.084846	10.712354	-1.077791	9.634563	11.8
73	22.605406	249.950207	10.299805	-3.474756	6.825049	11.1
74	21.318470	237.132497	10.012469	-1.333285	8.679184	11.1

SOURCE: FORM 15

YR	PROD	RESERVES	REVISIONS & ADDITIONS	R/P RATIO
63	9.351	188.540	N.A.	20.2
64	10.015	189.165	10.640	18.9
65	10.371	192.077	13.282	18.5
66	11.137	195.130	14.190	17.5
67	11.820	198.061	14.751	16.8
68	12.552	194.962	9.453	15.5
69	13.433	187.609	6.081	14.0
70	14.092	173.556	0.038	12.3
71	14.025	161.270	1.739	11.5
72	14.207	146.906	-0.157	10.3
73	13.680	134.317	1.092	9.8
74	12.965	120.543	-0.809	9.3

Table 1A

LOWER 48 STATES
(VOLUMES IN TRILLIONS OF CUBIC FEET)

SOURCE: AGA

YR	PROD	RESERVES	GROSS R.A.	REVISIONS	NET R.A.	R/P RATIO
45	N.A.	146.986723	N.A.	N.A.	N.A.	N.A.
46	4.915774	159.703813	N.A.	N.A.	17.632864	32.5
47	5.599235	165.025765	N.A.	N.A.	10.921187	29.5
48	5.975001	172.925056	N.A.	N.A.	13.823090	28.9
49	6.211124	179.401693	N.A.	N.A.	12.605615	28.9
50	6.855244	184.584745	N.A.	N.A.	11.985361	26.9
51	7.923673	192.758910	N.A.	N.A.	15.965808	24.3
52	8.592716	198.631566	N.A.	N.A.	14.267606	23.1
53	9.188365	210.298763	N.A.	N.A.	20.341933	22.9
54	9.375314	210.560931	N.A.	N.A.	9.547074	22.5
55	10.063167	222.482544	N.A.	N.A.	21.897616	22.1
56	10.848686	236.483215	N.A.	N.A.	24.716115	21.8
57	11.439891	245.230138	N.A.	N.A.	20.008056	21.4
58	11.422651	252.761790	N.A.	N.A.	18.896717	22.1
59	12.373064	261.170431	N.A.	N.A.	20.621254	21.1 3/
60	13.019054	262.219252	N.A.	N.A.	13.844259	20.1
61	13.377008	265.351846	N.A.	N.A.	16.350062	19.8
62	13.634408	270.644461	N.A.	N.A.	18.767866	19.9
63	14.541496	274.460509	N.A.	N.A.	18.103736	18.9
64	15.340611	279.420089	N.A.	N.A.	20.105080	18.2
65	16.244091	284.483598	N.A.	N.A.	21.157717	17.5
66	17.478154	286.385943	14.783970	4.462006	19.245976	16.4
67	18.358272	289.272449	14.837105	6.256270	21.093375	15.8
68	19.331747	282.097528	9.817312	2.220945	12.038257	14.6
69	20.635854	269.906692	9.613265	-1.275416	8.337849	13.1
70	21.815604	259.615657	11.278580	-0.156029	11.122551	11.9
71	21.922927	247.440277	11.052821	-1.615575	9.437246	11.3
72	22.365162	234.629403	10.712354	-1.314629	9.397725	10.5
73	22.474591	218.307581	10.053205	-3.546154	6.507051	9.7
74	21.174540	205.265885	9.658469	-1.347201	8.311268	9.7

SOURCE: FORM 15

YR	PROD	RESERVES	REVISIONS & ADDITIONS	R/P RATIO
63	9.351	188.540	N.A.	20.2
64	10.015	189.165	10.640	18.9
65	10.371	192.077	13.282	18.5
66	11.137	195.130	14.190	17.5
67	11.820	198.061	14.751	16.8
68	12.552	194.962	9.453	15.5
69	13.433	187.609	6.081	14.0
70	14.092	173.556	0.038	12.3
71	14.025	161.270	1.739	11.5
72	14.207	146.906	-0.157	10.3
73	13.680	134.317	1.092	9.8
74	12.965	120.543	-0.809	9.3

Table 2

ALASKA
(VOLUMES IN TRILLIONS OF CUBIC FEET)

SOURCE: AGA

YR	PROD	RESERVES	GROSS R.A.	REVISIONS	NET R.A.	R/P RATIO
59	N.A.	0.057660	N.A.	N.A.	N.A.	N.A.
60	0.000303	0.107078	N.A.	N.A.	0.049721	353.4
61	0.001642	0.921795	N.A.	N.A.	0.816359	561.4
62	0.003565	1.634321	N.A.	N.A.	0.716090	458.4
63	0.004529	1.690724	N.A.	N.A.	0.060932	373.3
64	0.006417	1.831365	N.A.	N.A.	0.147058	285.4
65	0.007602	1.985325	N.A.	N.A.	0.161562	261.2
66	0.012919	2.946862	0.498500	0.475956	0.974456	228.1
67	0.022566	3.635254	0.396650	0.314308	0.710958	161.1
68	0.041681	5.252324	0.863550	0.795201	1.658751	126.0
69	0.087336	5.202143	0.0	0.037155	0.037155	59.6
70	0.145200	31.130751	26.017500	0.056308	26.073808	214.4
71	0.153585	31.365341	0.0	0.388175	0.388175	204.2
72	0.146736	31.455443	0.0	0.236838	0.236838	214.4
73	0.130815	31.642626	0.246600	0.071398	0.317998	241.9
74	0.143930	31.866612	0.354000	0.013916	0.367916	221.4

Figure 2

ALASKA

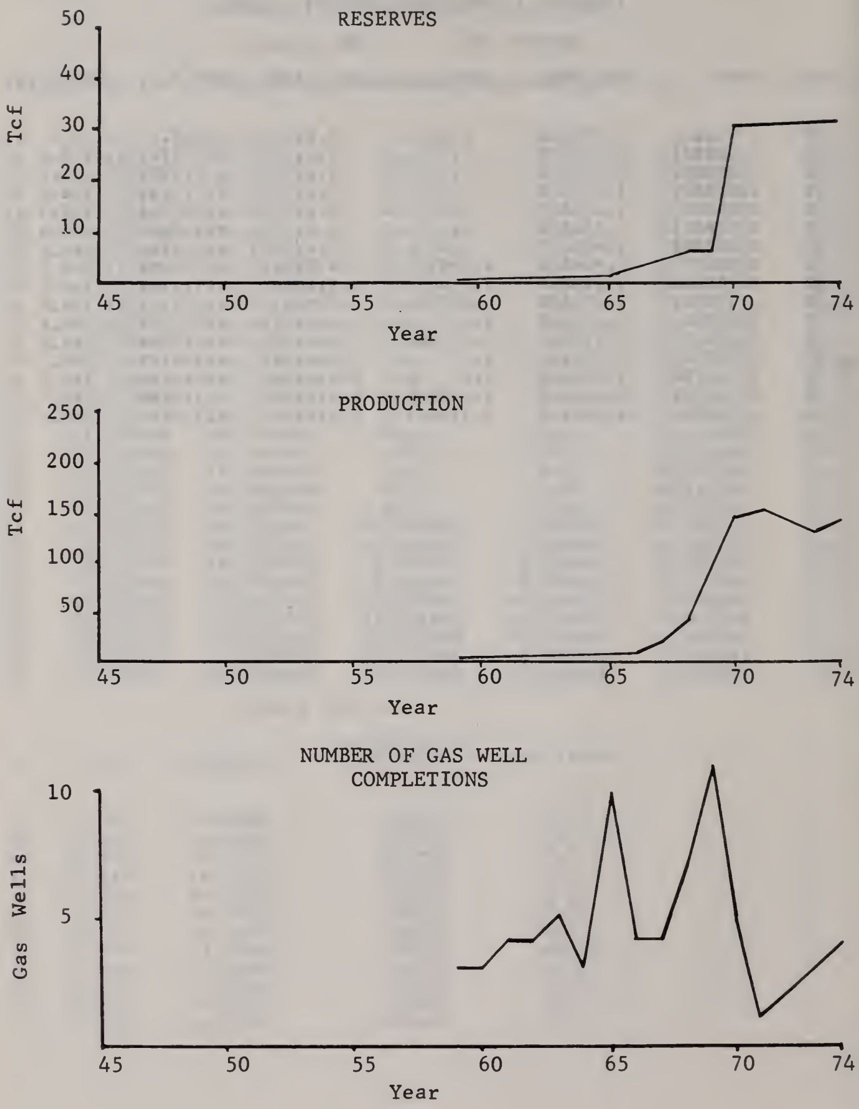


Table 3

SOUTH LOUISIANA
(VOLUMES IN TRILLIONS OF CUBIC FEET)

SOURCE: AGA

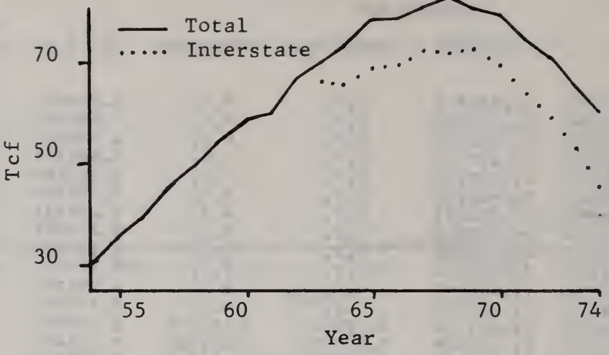
YR	PROD	RESERVES	GROSS R.A.	REVISIONS	NET R.A.	R/P RATIO
54	1.018054	30.833713	N.A.	N.A.	3.213932	30.3
55	1.194299	36.377591	N.A.	N.A.	6.738177	30.5
56	1.393433	39.332670	N.A.	N.A.	4.348512	28.2
57	1.587088	45.647335	N.A.	N.A.	7.901753	28.8
58	1.821394	49.048130	N.A.	N.A.	5.222189	26.9
59	2.253681	53.986158	N.A.	N.A.	7.191709	24.0
60	2.488398	57.726093	N.A.	N.A.	6.228333	23.2
61	2.770868	60.369816	N.A.	N.A.	5.414591	21.8
62	2.978552	66.562546	N.A.	N.A.	9.171282	22.3
63	3.351569	70.436530	N.A.	N.A.	7.225553	21.0
64	3.512994	73.880249	N.A.	N.A.	6.956713	21.0
65	4.008330	77.669804	N.A.	N.A.	7.797885	19.4
66	4.566476	78.613308	3.329205	2.180775	5.509980	17.2
67	5.371246	81.423519	3.959993	4.221464	8.181457	15.2
68	6.013455	83.392889	4.272095	3.710730	7.982825	13.9
69	6.789170	80.769437	3.118723	1.046995	4.165718	11.9
70	7.326045	79.093209	4.500204	1.149613	5.649817	10.8
71	7.680422	74.968645	5.228077	-1.680878	3.547199	9.8
72	7.987650	71.651006	3.898162	0.765666	4.663828	9.0
73	8.045165	66.175480	3.165716	-0.596319	2.569397	8.2
74	7.353051	61.215891	3.002079	-0.608550	2.393529	8.3

SOURCE: FORM 15

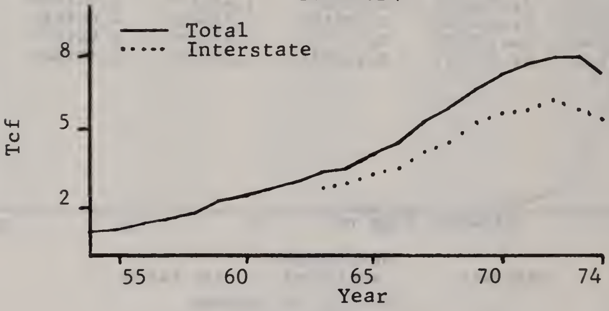
YR	PROD	RESERVES	REVISIONS & ADDITIONS	R/P RATIO
63	2.724	66.548	N.A.	24.4
64	2.949	65.963	2.364	22.4
65	3.198	68.916	6.150	21.6
66	3.623	69.820	4.527	19.3
67	4.194	72.729	7.104	17.3
68	4.649	72.162	4.082	15.5
69	5.288	73.289	6.415	13.9
70	5.834	69.972	2.517	12.0
71	5.955	64.103	0.086	10.8
72	6.229	59.142	1.269	9.5
73	5.940	53.627	0.424	9.0
74	5.538	46.077	-2.012	8.3

Figure 3
SOUTH LOUISIANA

RESERVES



PRODUCTION



NUMBER OF GAS WELL COMPLETIONS

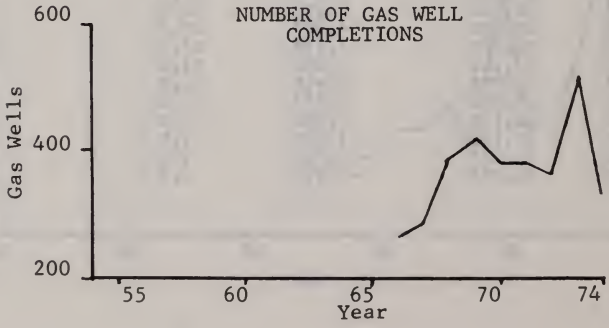


Table 4

ONSHORE SOUTH LOUISIANA + ZONE 1
(VOLUMES IN TRILLIONS OF CUBIC FEET)

SOURCE: AGA

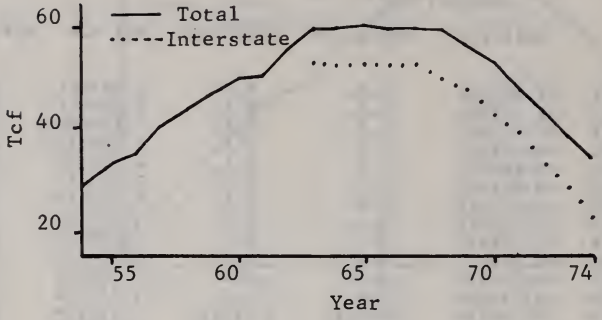
YR	PROD	RESERVES	GROSS R.A.	REVISIONS	NET R.A	R/P RATIO
54	0.956908	28.657833	N.A.	N.A.	2.993344	29.9
55	1.100545	32.976654	N.A.	N.A.	5.419366	30.0
56	1.297234	35.415096	N.A.	N.A.	3.735676	27.3
57	1.494972	40.536995	N.A.	N.A.	6.616871	27.1
58	1.675868	43.800257	N.A.	N.A.	4.939130	26.1
59	2.013489	46.904407	N.A.	N.A.	5.117639	23.3
60	2.216770	49.679255	N.A.	N.A.	4.991618	22.4
61	2.421084	51.327782	N.A.	N.A.	4.069611	21.2
62	2.508254	56.486024	N.A.	N.A.	7.666496	22.5
63	2.737428	59.070929	N.A.	N.A.	5.322333	21.6
64	2.838845	59.754697	N.A.	N.A.	3.522613	21.0
65	3.278155	60.748160	N.A.	N.A.	4.271618	18.5
66	3.650325	59.239729	1.599723	0.542171	2.141894	16.2
67	4.178399	59.124316	1.890778	2.172208	4.062986	14.1
68	4.540937	59.200280	2.144772	2.472129	4.616901	13.0
69	5.000939	56.666983	1.313659	1.153983	2.467642	11.3
70	5.103234	52.658138	1.785473	-0.691084	1.094389	10.3
71	5.197922	47.128723	1.209795	-1.549947	-0.340152	9.1
72	5.174552	42.919602	0.907045	0.052203	0.959248	8.3
73	4.849670	38.084856	0.923339	-0.908657	0.014682	7.9
74	4.091299	34.224699	1.052240	-0.821031	0.231209	8.4

SOURCE: FORM 15

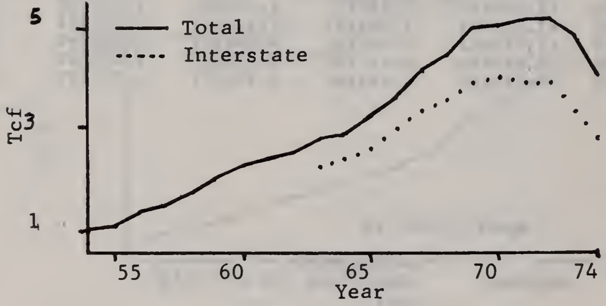
YR	PROD	RESERVES	REVISIONS & ADDITIONS	R/P RATIO
63	2.248	53.736	N.A.	23.9
64	2.411	52.579	1.254	21.8
65	2.612	53.265	3.298	20.4
66	2.920	52.626	2.281	18.0
67	3.357	53.062	3.793	15.8
68	3.639	49.796	0.373	13.7
69	3.935	47.428	1.567	12.1
70	4.026	42.838	-0.564	10.6
71	3.911	38.834	-0.093	9.9
72	3.948	32.889	-1.997	8.3
73	3.395	28.442	-1.052	8.4
74	2.797	23.617	-2.028	8.4

Figure 4
ONSHORE SOUTH LOUISIANA
+ ZONE 1

RESERVES



PRODUCTION



NUMBER OF GAS WELL COMPLETIONS 4/

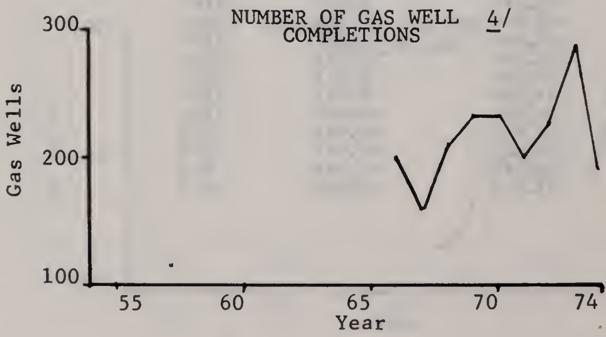


Table 5

OFFSHORE SOUTH LOUISIANA ZONES 2,3,4
(VOLUMES IN TRILLIONS OF CUBIC FEET)

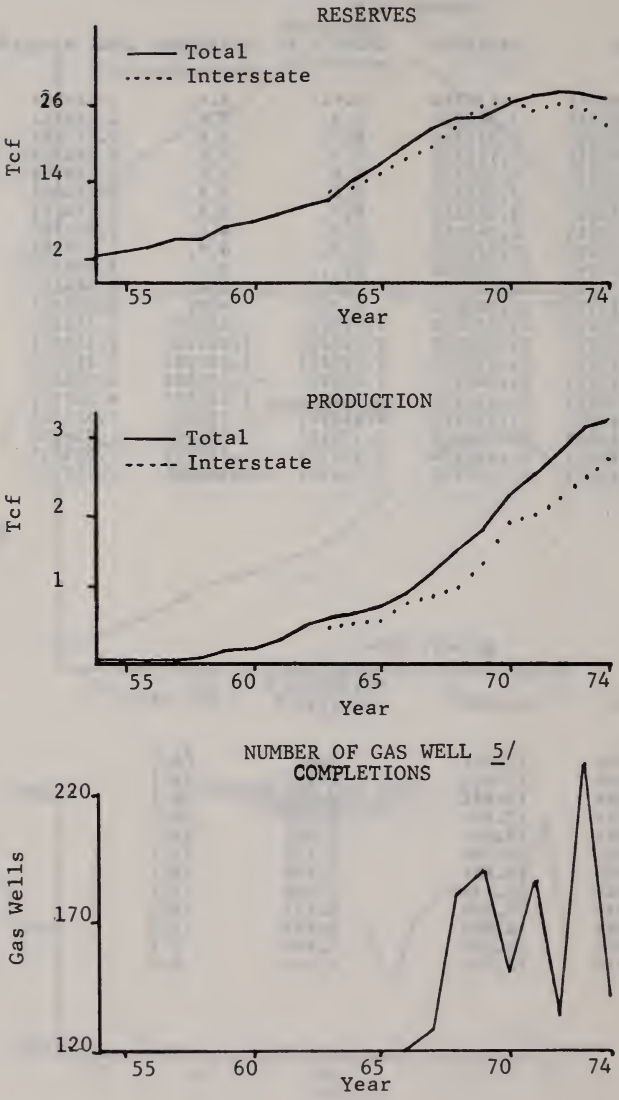
SOURCE: AGA

YR	PROD	RESERVES	GROSS R.A.	REVISIONS	NET R.A	R/P RATIO
54	0.061146	2.175880	N.A.	N.A.	0.220588	35.6
55	0.093754	3.400937	N.A.	N.A.	1.318811	36.3
56	0.096199	3.917574	N.A.	N.A.	0.612836	40.7
57	0.092116	5.110340	N.A.	N.A.	1.284882	55.5
58	0.145526	5.247873	N.A.	N.A.	0.283059	36.1
59	0.240192	7.081751	N.A.	N.A.	2.074070	29.5
60	0.271628	8.046838	N.A.	N.A.	1.236715	29.6
61	0.349784	9.042034	N.A.	N.A.	1.344980	25.9
62	0.470298	10.076522	N.A.	N.A.	1.504786	21.4
63	0.614141	11.365601	N.A.	N.A.	1.903220	18.5
64	0.674149	14.125552	N.A.	N.A.	3.434100	21.0
65	0.730175	16.921644	N.A.	N.A.	3.526267	23.2
66	0.916151	19.373579	1.729482	1.638604	3.368086	21.1
67	1.192847	22.299203	2.069215	2.049256	4.118471	18.7
68	1.472518	24.192609	2.127323	1.238601	3.365924	16.4
69	1.788231	24.102454	1.805064	-0.106988	1.698076	13.5
70	2.222811	26.435071	2.714731	1.840697	4.555428	11.9
71	2.482500	27.839922	4.018282	-0.130931	3.887351	11.2
72	2.813098	28.731404	2.991117	0.713463	3.704580	10.2
73	3.195495	28.090624	2.242377	0.312338	2.554715	8.8
74	3.261752	26.991192	1.949839	0.212481	2.162320	8.3

SOURCE: FORM 15

YR	PROD	RESERVES	REVISIONS & ADDITIONS	R/P RATIO
63	0.476	12.812	N.A.	26.9
64	0.538	13.384	1.110	24.9
65	0.586	15.651	2.853	26.7
66	0.703	17.194	2.246	24.5
67	0.837	19.667	3.309	23.5
68	1.010	22.366	3.709	22.1
69	1.353	25.861	4.848	19.1
70	1.808	27.134	3.082	15.0
71	2.044	25.269	0.179	12.4
72	2.281	26.253	3.264	11.5
73	2.545	25.185	1.478	9.9
74	2.741	22.460	0.016	8.2

Figure 5
OFFSHORE SOUTH LOUISIANA
ZONES 2, 3, 4



RESERVES

PRODUCTION

NUMBER OF GAS WELL 5/
COMPLETIONS

Table 6

TEXAS GULF COAST
(VOLUMES IN TRILLIONS OF CUBIC FEET)

SOURCE: AGA 6/

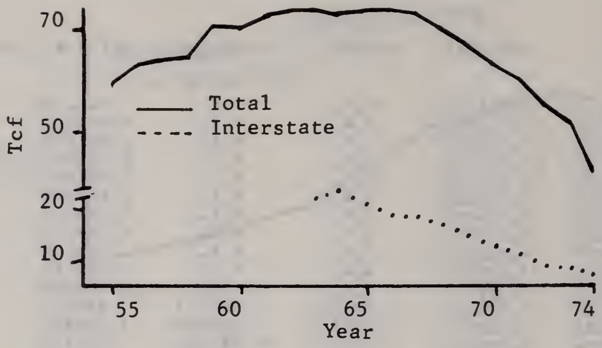
YR	PROD	RESERVES	GROSS R.A.	REVISIONS	NET R.A.	R/P RATIO
55	N.A.	59.051166	N.A.	N.A.	N.A.	N.A.
56	2.577701	63.413783	N.A.	N.A.	6.940307	24.6
57	2.590210	64.790846	N.A.	N.A.	3.967280	25.0
58	2.655947	65.044469	N.A.	N.A.	2.909569	24.5
59	2.791371	71.180265	N.A.	N.A.	8.927167	25.5
60	3.034340	70.795225	N.A.	N.A.	2.649299	23.3
61	3.026436	72.984441	N.A.	N.A.	5.215652	24.1
62	3.149661	74.299309	N.A.	N.A.	4.464531	23.6
63	3.289949	74.334368	N.A.	N.A.	3.325007	22.6
64	3.403215	73.629347	N.A.	N.A.	2.698194	21.6
65	3.589888	74.377597	N.A.	N.A.	4.337989	20.7
66	3.750423	74.526225	2.895710	1.003147	3.898857	19.9
67	3.812072	74.022323	2.254573	1.050902	3.305475	19.4
68	3.813779	70.920365	1.084271	-0.381301	0.702970	18.6
69	3.962189	67.540216	1.340837	-0.761435	0.579402	17.0
70	4.047083	64.115555	1.295874	-0.673129	0.622745	15.8
71	3.984091	60.844298	1.214627	-0.499132	0.715495	15.3
72	3.894372	56.147525	1.140800	-1.999490	-0.858690	14.4
73	3.849289	47.865507	1.016635	-5.445640	-4.429005	12.4
74	3.572061	43.176156	1.244394	-2.374380	-1.129986	12.1

SOURCE: FORM 15

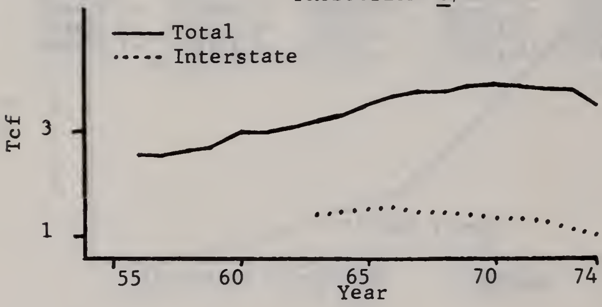
YR	PROD	RESERVES	REVISIONS & ADDITIONS	R/P RATIO
63	1.439	22.840	N.A.	15.9
64	1.470	23.021	1.651	15.7
65	1.502	21.728	0.209	14.5
66	1.518	19.698	-0.512	13.0
67	1.463	19.527	1.292	13.3
68	1.443	17.127	-0.957	11.9
69	1.400	15.058	-0.668	10.8
70	1.373	12.563	-1.122	9.2
71	1.297	11.348	0.082	8.7
72	1.266	9.242	-0.841	7.3
73	1.142	8.522	0.422	7.5
74	1.042	7.193	-0.287	6.9

Figure 6
TEXAS GULF COAST 6/

RESERVES



PRODUCTION 6/



NUMBER OF GAS WELL 6/
COMPLETIONS

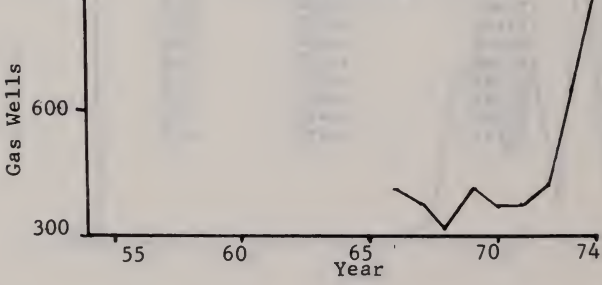


Table 7

HUGOTON-ANADARKO
(VOLUMES IN TRILLIONS OF CUBIC FEET)

SOURCE: AGA

YR	PROD	RESERVES	GROSS R.A.	REVISIONS	NET R.A.	R/P RATIO
55	N.A.	45.205659	N.A.	N.A.	N.A.	N.A.
56	1.881344	46.385716	N.A.	N.A.	3.051151	24.7
57	1.883551	47.322972	N.A.	N.A.	2.815238	25.1
58	1.819622	49.201455	N.A.	N.A.	3,698058	27.0
59	1.999160	49.431585	N.A.	N.A.	2.217644	24.7
60	2.044748	48.524538	N.A.	N.A.	1.116605	23.7
61	2.176310	47.030637	N.A.	N.A.	0.683422	21.6
62	2.244455	46.495496	N.A.	N.A.	1.700336	20.7
63	2.405816	45.192407	N.A.	N.A.	1.101513	18.8
64	2.582191	44.956745	N.A.	N.A.	2.344176	17.4
65	2.687309	43.548284	N.A.	N.A.	1.272804	16.2
66	2.861569	42.069172	N.A.	N.A.	1.387915	14.7
67	3.001673	41.395977	N.A.	N.A.	2.328630	13.8
68	2.961611	39.121428	N.A.	N.A.	0.675904	13.2
69	3.093682	36.894586	N.A.	N.A.	0.852778	11.9
70	3.299553	35.096990	N.A.	N.A.	1.459618	10.6
71	3.201881	33.299985	N.A.	N.A.	1.395150	10.4
72	3.338960	31.444529	N.A.	N.A.	1.489903	9.4
73	3.383881	30.820984	N.A.	N.A.	2.738755	9.1
74	3.377302	30.406188	N.A.	N.A.	2.978453	9.0

SOURCE: FORM 15

YR	PROD	RESERVES	REVISIONS & ADDITIONS	R/P RATIO
63	1.962	40.223	N.A.	20.5
64	2.105	39.553	1.435	18.8
65	2.160	38.136	0.744	17.7
66	2.313	37.280	1.457	16.1
67	2.436	36.478	1.634	15.0
68	2.367	36.524	2.414	15.4
69	2.499	35.318	1.292	14.1
70	2.597	33.430	0.709	12.9
71	2.579	31.156	0.305	12.1
72	2.617	28.954	0.414	11.1
73	2.587	26.723	0.357	10.3
74	2.552	25.298	1.127	9.9

Figure 7
HUGOTON - ANADARKO

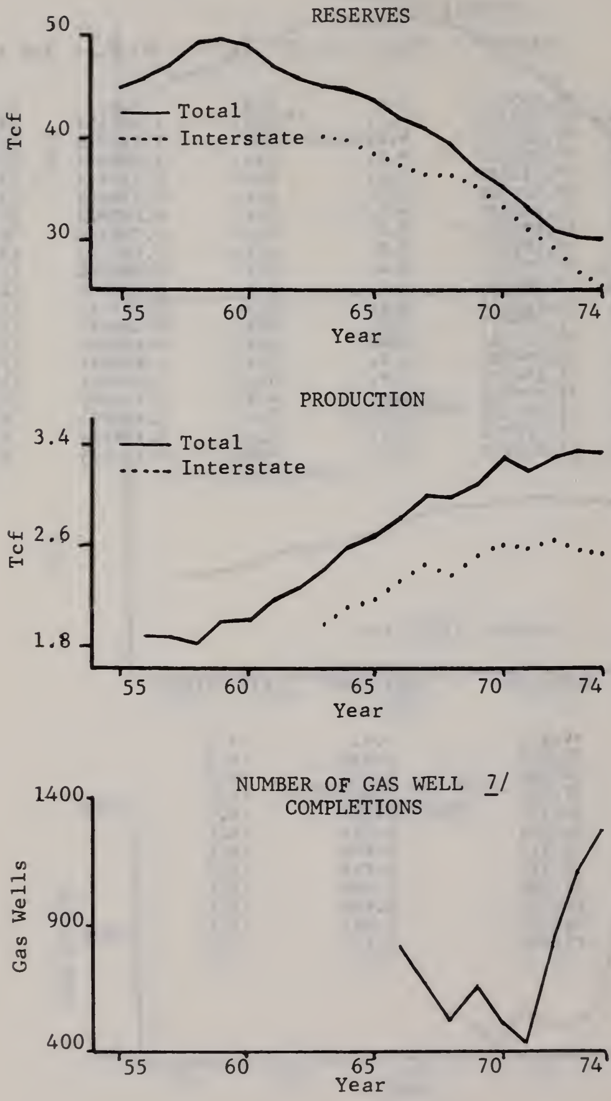


Table 8

PERMIAN BASIN
(VOLUMES IN TRILLIONS OF CUBIC FEET)

SOURCE: AGA

YR	PROD	RESERVES	GROSS R.A.	REVISIONS	NET R.A.	R/P RATIO
55	N.A.	22.659488	N.A.	N.A.	N.A.	N.A.
56	1.424691	24.294650	N.A.	N.A.	3.092602	17.1
57	1.439034	23.903264	N.A.	N.A.	1.050276	16.6
58	1.411273	24.913125	N.A.	N.A.	2.420289	17.7
59	1.412835	24.990319	N.A.	N.A.	1.491890	17.7
60	1.444686	24.768332	N.A.	N.A.	1.218743	17.1
61	1.480804	23.769401	N.A.	N.A.	0.482007	16.1
62	1.470299	22.561338	N.A.	N.A.	0.254127	15.3
63	1.432849	22.814374	N.A.	N.A.	1.696592	15.9
64	1.647411	24.727997	N.A.	N.A.	3.558192	15.0
65	1.715941	26.727497	N.A.	N.A.	3.716036	15.6
66	1.783819	30.127772	4.518690	0.670599	5.189289	16.9
67	1.797032	32.616943	3.621975	0.666971	4.288946	18.2
68	2.122701	31.963663	1.230961	0.241856	1.472817	15.1
69	2.371182	29.977869	1.304147	-0.915454	0.388693	12.6
70	2.764581	27.695941	1.964988	-1.477323	0.487665	10.0
71	2.864508	26.622622	1.844665	-0.049782	1.794883	9.3
72	3.134232	25.268601	1.877541	-0.092721	1.784820	8.1
73	3.224497	24.503885	1.678510	0.768580	2.447090	7.6
74	3.231479	23.207458	1.437479	0.489331	1.926810	7.2

SOURCE: FORM 15 8/

YR	PROD	RESERVES	REVISIONS & ADDITIONS	R/P RATIO
63	0.920	18.916	N.A.	20.6
64	1.056	19.841	1.981	18.8
65	1.066	22.801	4.026	21.4
66	1.151	27.194	5.544	23.6
67	1.208	28.989	3.004	24.0
68	1.449	30.178	2.638	20.8
69	1.655	26.428	-2.095	16.0
70	1.809	22.203	-2.415	12.3
71	1.845	20.948	0.589	11.4
72	1.815	18.093	-1.039	10.0
73	1.817	15.428	-0.848	8.5
74	1.729	13.691	-0.008	7.9

Figure 8
PERMIAN BASIN

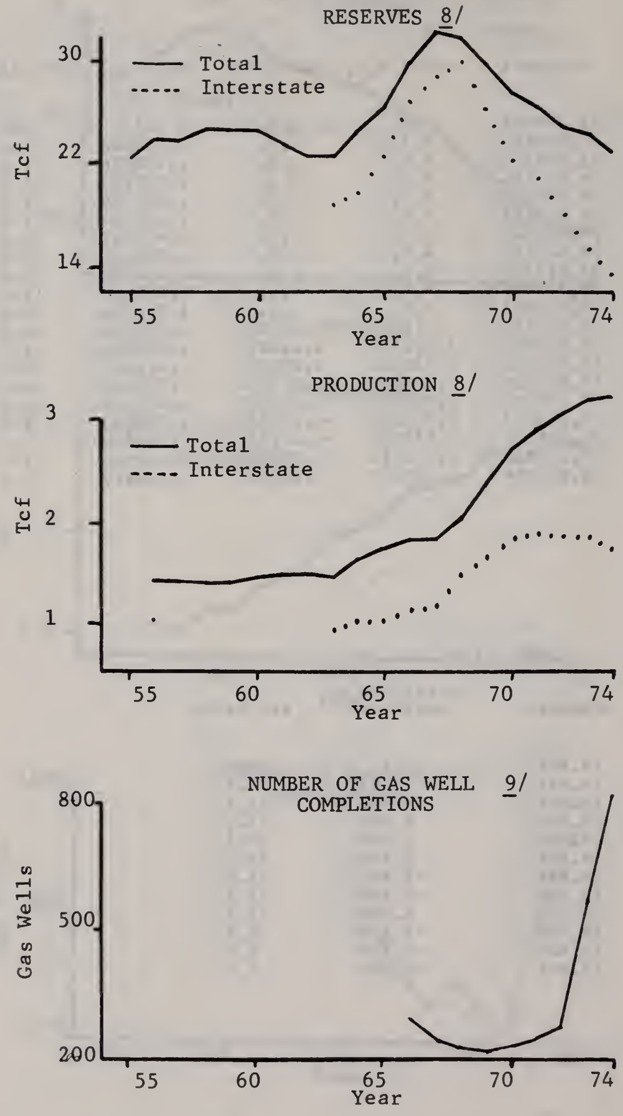


Table 9

OTHER SOUTHWEST
(VOLUMES IN TRILLIONS OF CUBIC FEET)

SOURCE: AGA

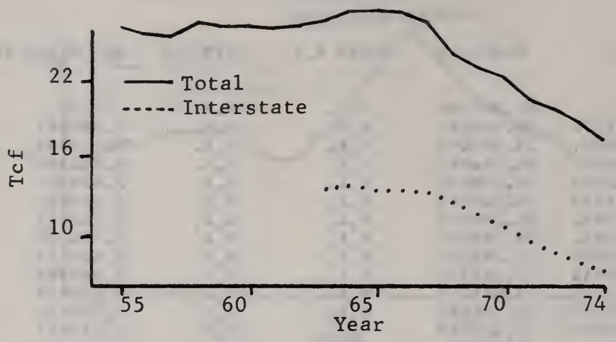
YR	PROD	RESERVES	GROSS R.A.	REVISIONS	NET R.A.	R/P RATIO
55	N.A.	26.265799	N.A.	N.A.	N.A.	N.A.
56	2.121300	25.728693	N.A.	N.A.	1.585467	12.1
57	2.329101	25.553595	N.A.	N.A.	2.133987	11.0
58	2.192660	26.496847	N.A.	N.A.	3.136705	12.1
59	2.262603	26.275404	N.A.	N.A.	2.025759	11.6
60	2.241543	26.265763	N.A.	N.A.	2.210451	11.7
61	2.112286	26.249409	N.A.	N.A.	2.102811	12.4
62	2.068936	26.379160	N.A.	N.A.	2.184009	12.8
63	2.247681	26.787260	N.A.	N.A.	2.640577	11.9
64	2.203434	27.459794	N.A.	N.A.	2.865858	12.5
65	2.171544	27.553783	N.A.	N.A.	2.257729	12.7
66	2.285199	27.406485	N.A.	N.A.	2.093106	12.0
67	2.184547	26.403808	N.A.	N.A.	1.110897	12.1
68	2.102603	24.235810	N.A.	N.A.	-0.084348	11.5
69	2.152288	23.236084	N.A.	N.A.	1.122190	10.8
70	2.134371	22.303952	N.A.	N.A.	1.142205	10.4
71	1.969871	20.838404	N.A.	N.A.	0.471300	10.6
72	1.810639	19.913162	N.A.	N.A.	0.815045	11.0
73	1.775882	18.821312	N.A.	N.A.	0.678299	10.6
74	1.589816	17.710211	N.A.	N.A.	0.516125	11.1

SOURCE: FORM 15

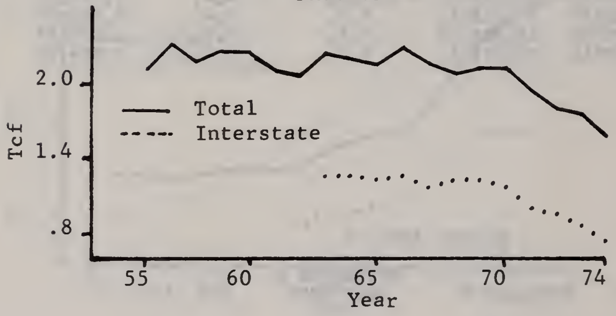
YR	PROD	RESERVES	REVISIONS & ADDITIONS	R/P RATIO
63	1.254	13.602	N.A.	10.8
64	1.265	13.971	1.634	11.0
65	1.221	13.459	0.708	11.0
66	1.246	13.659	1.446	11.0
67	1.186	13.425	0.953	11.3
68	1.215	12.530	0.319	10.3
69	1.210	11.799	0.479	9.8
70	1.184	10.722	0.107	9.1
71	1.015	9.478	-0.229	9.3
72	0.957	8.779	0.258	9.2
73	0.872	7.936	0.029	9.1
74	0.771	7.243	0.078	9.4

Figure 9
OTHER SOUTHWEST

RESERVES



PRODUCTION



NUMBER OF GAS WELL 10/
COMPLETIONS

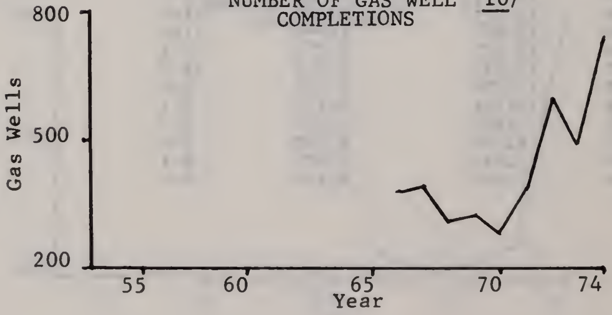


Table 10

ROCKY MOUNTAIN
(VOLUMES IN TRILLIONS OF CUBIC FEET)

SOURCE: AGA

YR	PROD	RESERVES	GROSS R.A.	REVISIONS	NET R.A.	R/P RATIO
56	0.509334	23.398545	N.A.	N.A.	4.949725	45.9
57	0.704120	23.736156	N.A.	N.A.	1.035260	33.7
58	0.650013	23.765642	N.A.	N.A.	0.680396	36.6
59	0.727908	21.183990	N.A.	N.A.	-1.857475	29.1
60	0.786831	19.380358	N.A.	N.A.	-1.032554	24.6
61	0.824926	19.698677	N.A.	N.A.	1.143282	23.9
62	0.760997	19.004899	N.A.	N.A.	0.037922	25.0
63	0.761120	19.375252	N.A.	N.A.	1.105690	25.5
64	0.910761	18.934418	N.A.	N.A.	0.454998	20.8
65	0.990721	18.778179	N.A.	N.A.	0.815935	19.0
66	1.070133	17.952849	0.259501	-0.047233	0.212268	16.8
67	1.063954	18.495570	1.582337	0.010862	1.593199	17.4
68	1.138145	17.974665	0.482928	0.114084	0.597012	15.8
69	1.128413	17.514030	0.719260	-0.061357	0.657903	15.5
70	1.106870	17.312785	0.700589	0.196814	0.897403	15.6
71	1.149846	17.087479	0.767210	0.132500	0.899710	14.9
72	1.202692	16.482833	0.755076	-0.168469	0.586607	13.7
73	1.223265	16.577380	1.189670	0.119681	1.309351	13.6
74	1.167371	15.836439	0.862661	-0.399639	0.463022	13.6

SOURCE: FORM 15

YR	PROD	RESERVES	REVISIONS & ADDITIONS	R/P RATIO
63	0.570	20.362	N.A.	35.7
64	0.650	20.340	0.628	31.3
65	0.698	20.837	1.196	29.8
66	0.750	21.219	1.131	28.3
67	0.778	20.847	0.406	26.8
68	0.843	20.395	0.391	24.2
69	0.816	19.868	0.289	24.3
70	0.838	19.706	0.677	23.5
71	0.878	18.917	0.089	21.5
72	0.931	19.155	1.169	20.6
73	0.913	18.812	0.571	20.6
74	0.902	17.971	0.061	19.9

Figure 10

ROCKY MOUNTAIN

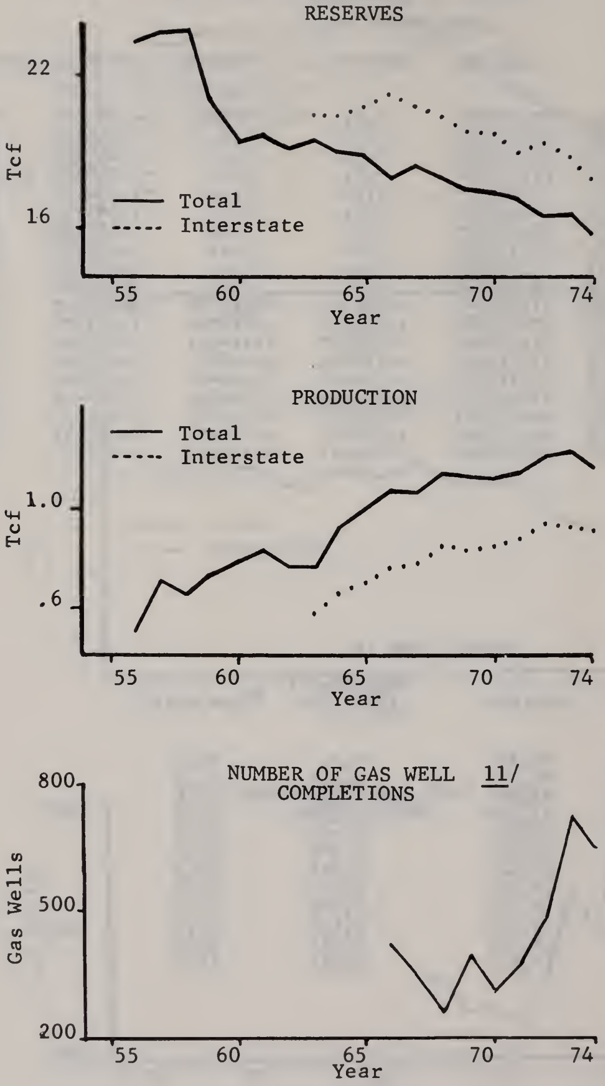


Table 11

APPALACHIA 12/
(VOLUMES IN TRILLIONS OF CUBIC FEET)

SOURCE: AGA

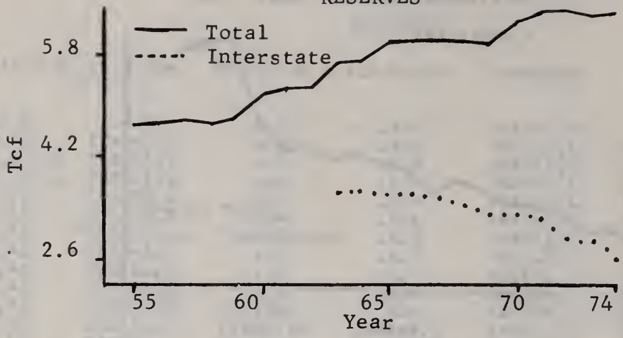
YR	PROD	RESERVES	GROSS R.A.	REVISIONS	NET R.A.	R/P RATIO
55	N.A.	4.709795	N.A.	N.A.	N.A.	N.A.
56	0.434634	4.751721	N.A.	N.A.	0.366453	10.9
57	0.414871	4.812380	N.A.	N.A.	0.396313	11.6
58	0.413710	4.740527	N.A.	N.A.	0.309425	11.5
59	0.431707	4.847459	N.A.	N.A.	0.441043	11.2
60	0.444739	5.207199	N.A.	N.A.	0.694145	11.7
61	0.411303	5.345851	N.A.	N.A.	0.443439	13.0
62	0.383009	5.360349	N.A.	N.A.	0.368924	14.0
63	0.398069	5.691268	N.A.	N.A.	0.653069	14.3
64	0.405004	5.740466	N.A.	N.A.	0.347907	14.2
65	0.416431	5.975942	N.A.	N.A.	0.575367	14.4
66	0.430942	6.139985	0.417803	0.190573	0.608376	14.2
67	0.448270	6.106358	0.368062	0.021655	0.389717	13.6
68	0.450132	6.094077	0.351234	0.035375	0.386609	13.5
69	0.434724	5.970834	0.424371	-0.148202	0.276169	13.7
70	0.459307	6.359066	0.526169	0.017799	0.543968	13.8
71	0.449294	6.501499	0.418028	-0.003129	0.414899	14.5
72	0.426830	6.558130	0.479518	0.021175	0.500693	15.4
73	0.410631	6.413161	0.552460	-0.005446	0.547014	15.6
74	0.411008	6.519605	0.454134	0.130706	0.584840	15.9

SOURCE: FORM 15

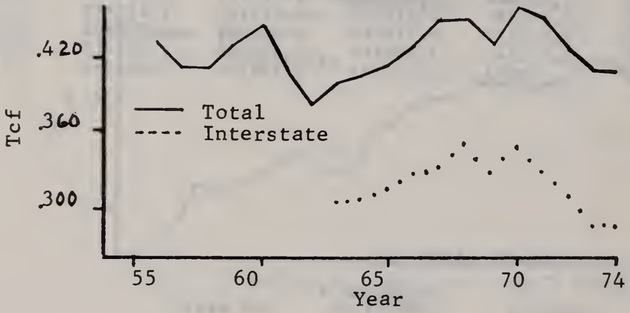
YR	PROD	RESERVES	REVISIONS & ADDITIONS	R/P RATIO
63	0.304	3.695	N.A.	12.1
64	0.308	3.739	0.352	12.1
65	0.318	3.705	0.284	11.7
66	0.327	3.723	0.345	11.4
67	0.333	3.648	0.258	10.9
68	0.352	3.432	0.136	9.8
69	0.329	3.273	0.170	10.0
70	0.346	3.261	0.334	9.4
71	0.329	3.236	0.304	9.8
72	0.311	2.789	-0.136	9.0
73	0.285	2.776	0.272	9.7
74	0.286	2.616	0.126	9.1

Figure 11
APPALACHIA

RESERVES



PRODUCTION



NUMBER OF GAS WELL 13/
COMPLETIONS

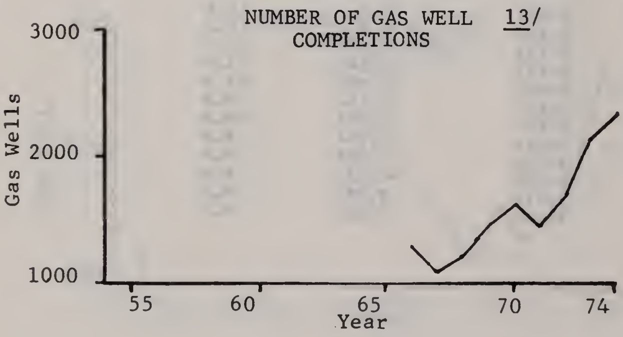


Table 12

ALL OTHER 14/
(VOLUMES IN TRILLIONS OF CUBIC FEET)

SOURCE: AGA

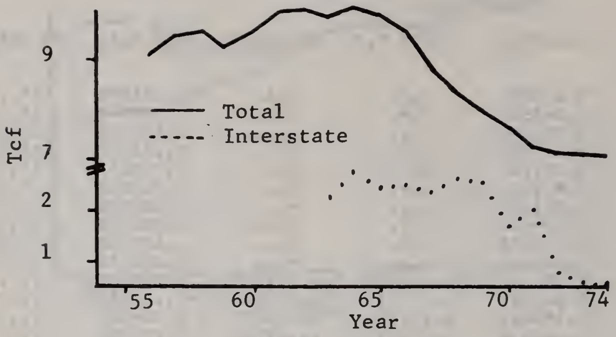
YR	PROD	RESERVES	GROSS R.A.	REVISIONS	NET R.A.	R/P RATIO
56	0.506249	9.177437	N.A.	N.A.	0.381898	18.1
57	0.491916	9.463590	N.A.	N.A.	0.707949	19.2
58	0.458032	9.551595	N.A.	N.A.	0.520086	20.9
59	0.493799	9.275251	N.A.	N.A.	0.183517	18.8 3/
60	0.533769	9.551744	N.A.	N.A.	0.759237	17.9
61	0.574075	9.903614	N.A.	N.A.	0.864858	17.3
62	0.578499	9.981364	N.A.	N.A.	0.586735	17.3
63	0.654443	9.829050	N.A.	N.A.	0.355735	15.0
64	0.675601	10.091073	N.A.	N.A.	0.879042	14.9
65	0.664527	9.852512	N.A.	N.A.	0.383972	14.8
66	0.729593	9.550147	0.164807	0.181378	0.346185	13.1
67	0.679478	8.807951	0.309039	-0.413985	-0.104946	13.0
68	0.729321	8.394631	0.355345	-0.050877	0.304468	11.5
69	0.704206	8.003636	0.214430	0.080566	0.294996	11.4
70	0.677794	7.638159	0.297054	0.022076	0.319130	11.3
71	0.623014	7.277345	0.295451	-0.096841	0.198610	11.7
72	0.569787	7.163617	0.575525	-0.160006	0.415519	12.6
73	0.561981	7.129872	0.582973	0.063177	0.646150	12.7
74	0.472452	7.193937	0.306975	0.271500	0.578475	15.2

SOURCE: FORM 15

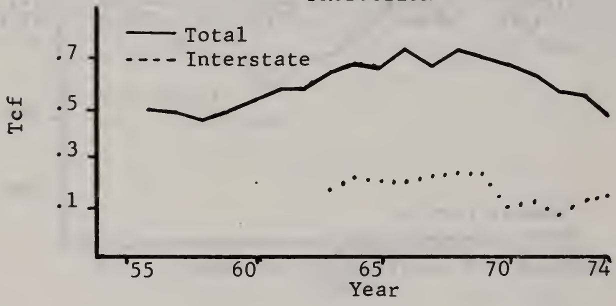
YR	PROD	RESERVES	REVISIONS & ADDITIONS	R/P RATIO
63	0.178	2.354	N.A.	13.2
64	0.212	2.737	0.595	12.9
65	0.208	2.495	-0.034	12.0
66	0.209	2.537	0.251	12.1
67	0.222	2.418	0.103	10.9
68	0.234	2.614	0.430	11.2
69	0.236	2.576	0.198	10.9
70	0.111	1.699	-0.766	15.3
71	0.127	2.084	0.512	16.4
72	0.081	0.752	-1.251	9.3
73	0.124	0.493	-0.135	4.0
74	0.145	0.454	0.106	3.1

Figure 12
ALL OTHER 14/

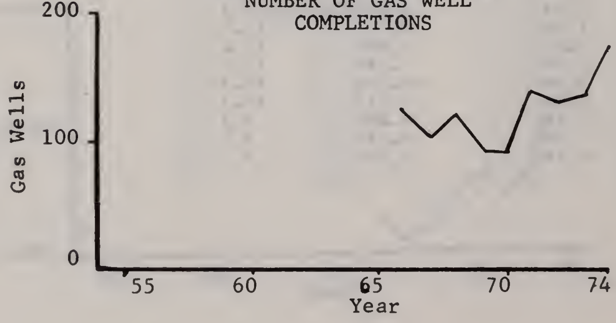
RESERVES



PRODUCTION



NUMBER OF GAS WELL COMPLETIONS



FOOTNOTES

1/ AGA and Form 15 data consist of total non-associated and associated-dissolved gas.

2/ Drilling statistics are not available to allow an exact geographical match with all of the FPC areas which are the basis of reserve and production compilations. Therefore proxy areas as described by the appropriate footnote have been used to assemble "Number of Gas Well Completions".

"Number of Gas Well Completions" includes total of development and exploratory wells.

These statistics may not include all wells drilled in a given year because AAPG statistical procedures may result in certain wells being held in a "suspense file" until all required well data have been made available. For additional detail see annual AAPG bulletin on North American developments usually published in August.

3/ 1959 AGA data include Alaska.

4/ "Number of Gas Well Completions" includes Onshore South Louisiana only.

5/ "Number of Gas Well Completions" includes Louisiana Offshore Zones 1,2,3, and 4. (State and Federal).

6/ The north portion of Texas Railroad Commission District No. 1 is included in this area for AGA and API data only.

7/ Hugoton-Anadarko proxy area includes Oklahoma, Kansas, and Texas Railroad District 10.

8/ The north portion of Texas Railroad Commission District No. 1 is included in this area for Form 15 data only.

9/ Permian proxy area includes Texas Railroad Districts 7B, 7C, 8, 8A, and Eastern New Mexico.

10/ Other Southwest proxy area includes North Louisiana, Arkansas, Alabama, and Texas Railroad Districts 5,6, and 9.

11/ Rocky Mountain proxy area includes Colorado, Montana, Nebraska, Western New Mexico, North Dakota, South Dakota, Utah, and Wyoming.

FOOTNOTES CONT.

12/ Indiana is included in the All Other category for AGA data only.

13/ Appalachia proxy area includes Illinois, Kentucky, New York, Ohio, Pennsylvania, Virginia, and West Virginia.

14/ All Other includes reserves, production and gas wells not included in the previous area detail.

SOURCES

Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity (1966-1974), published jointly by AGA, API and CPA.

Special Statements on natural gas reserves and production covering those portions of the FPC pricing areas not specifically identified in the above annual reports (1954-1974), prepared by AGA.

The Gas Supplies of Interstate Natural Gas Pipeline Companies (1964-1973), prepared by the Federal Power Commission.

FPC Form 15 (1974).

Annual American Association of Petroleum Geologists Bulletins and American Petroleum Institute Quarterly Review of Drilling Statistics for the United States (1966-1974).

World Oil Forecast - Review Issues: February 15, (1946-1965).

APPENDIX B

Table 1
PROJECTED PRODUCTIVE CAPABILITY
(Volumes in Trillion Cubic Feet)

Year	Traditional Areas 1/	Pacific OCS	Atlantic OCS	Alaska Offshore	Alaska Onshore 2/	Total
1975	20.28	--	--	--	.15	20.43
1976	19.47	--	--	--	.15	19.62
1977	18.67	--	--	--	.15	18.82
1978	17.89	--	--	--	.15	18.04
1979	17.13	.04	--	--	.15	17.32
1980	16.42	.08	.18	--	.65	17.33
1981	15.77	.11	.40	--	1.15	17.43
1982	15.17	.18	.48	.14	1.15	17.12
1983	14.65	.21	.56	.45	1.15	17.02
1984	14.21	.19	.58	.78	1.15	16.89
1985	13.82	.21	.59	.96	1.15	16.75

1/ Lower 48 states onshore, Santa Barbara Channel and the Gulf of Mexico.

2/ Current production is from both the Kenai Peninsula and Cook Inlet areas.

Note: The projected productive capability for the traditional areas was generated with the use of the National Availability Curve (NAC). This technique is described on page 10 of "A Realistic View of U.S. Natural Gas Supply," issued by the Bureau of Natural Gas of the Federal Power Commission in December 1974. The productive capability for the frontier areas was developed on a judgmental basis and represents what we believe to be reasonable levels of production that may result from the development of leases included in the Interior Department's currently proposed leasing schedule.

Table 2
PROJECTED RESERVE ADDITIONS
(Volumes in Trillion Cubic Feet)

Year	Traditional Areas 1/	Pacific OCS	Atlantic OCS	Alaska Offshore	Alaska Onshore	Total
1975	9.31	--	--	--	2/	9.31
1976	9.31	--	--	--	--	9.31
1977	9.31	.30	.72	1.08	--	11.41
1978	9.31	.42	1.28	1.80	--	12.81
1979	9.31	.50	1.15	2.17	--	13.13
1980	9.31	.22	.55	1.45	--	11.53
1981	9.31	.16	.70	1.16	--	11.33
1982	9.31	.43	.70	.69	--	11.13
1983	9.31	.20	.42	.86	--	10.79
1984	9.31	.16	.65	.87	--	10.99
1985	9.31	.12	.37	.89	--	10.69
Totals	102.41	2.51	6.54	10.97	--	122.43

1/ Lower 48 states onshore and the Gulf of Mexico.

2/ Additional gas reserves will undoubtedly be discovered on the North Slope during the 1975-1985 period. However, it is unlikely that production from these reserves would significantly increase national production before 1985 because of the lack of an adequate transportation system.

APPENDIX B

Table 3

CANADA NATURAL GAS EXPORT POTENTIAL
(Billion Cubic Feet @1,000 BTU/Cubic Foot)

Year (1)	Annual Canadian Deliverability Forecast 1/ (2)	Annual Canadian Demand Forecast 2/ (3)	Gas Available For Export (4)	Authorized Annual Exports 3/ (5)	Projected Export Curtailments (6)
1975	2,651	1,714	937	1,033	96
1976	2,788	1,846	942	1,024	82
1977	2,909	2,026	883	1,023	140
1978	2,967	2,243	724	1,023	299
1979	2,970	2,370	600	1,023	423
1980	3,043	2,523	520	981	461
1981	3,041	2,651	390	946	556
1982	2,986	2,748	238	898	660
1983	2,985	2,831	154	898	744
1984	2,992	2,929	63	898	835
1985	2,927	3,047	(120)	886	886

1/ Forecast by N.E.B. which considers reserve additions from traditional producing areas but excludes frontier areas.

2/ N.E.B. "medium" demand forecast case.

3/ Based on authorized volumes as scheduled by N.E.B.

Sources: Columns 2 and 3 from "Canadian Natural Gas Supply & Requirements" National Energy Board, April 1975.

Column 5 from National Energy Board's Annual Report for 1974.

APPENDIX B

TABLE 4
FEDERAL POWER COMMISSION LONG-TERM LNG IMPORT APPLICATIONS
August 1, 1975

	Source	Importer	FPC Docket No.	Delivery Point 1/	Deliveries 1/ (MMcf/day)	Deliveries 1/ (Bcf/Yr.)	Time Frame 1/	Status
1	Skikda, Algeria	Distrigas Corp.	CP70-196 2/	Everett, Mass. & Staten Is., N. Y.	42	15	1971 (20 Years)	Approved 3-9-72 and 6-7-72 Reopened 9-12-74
2.	Arzew, Algeria	Columbia LNG Corp.	CP71-68 3/	Cove Point, Md	319	116	1976-1977 (25 Years)	Approved 6-28-72 and 10-5-72 Reopened 7-15-74
		Consolidated Gas Supply Corp.	CP71-153 4/	Cove Point Md.	372	136		
		Southern Energy Co.	CP71-151 5/	Savannah, Ga.	372	136		
3.	Skikda, Algeria	Eascogas LNG, Inc.	CP73-47 6/	Staten Island, N. Y., & Providence, R. I.	326 (year 1-2) 487 (year 3) 652 (year 4-20) 408 (year 22-22)	119 178 238 149	1975-1976 (22 years)	Partial Approval 12-28-73
4.	Skikda, Algeria	Distrigas Corp.	CP73-132 7/	Everett, Mass., & Staten Is., N. Y.	123	45	1975 (20 years)	Withdrawn 8/ 5-9-75
5.	Arzew, Algeria	El Paso Eastern Co.	CP73-258 9/	Gloucester Co., N. J.	422	154	1978 (25 years)	Pending
		Transco Energy Co.	CP73-267 10/	Gloucester Co., N. J.	422	154		
		Southern Energy Co.	CP73-271 11/	Savannah, Ga.	112	41		
		Consolidated System LNG Co.	CP73-284 12/	Cove Point, Md.	169	62		
6.	Arzew, Deilys, or Skikda, Algeria	Trunkline LNG Co.	CP74-139 13/	Lake Charles, La.	490	179	1979 (20 years)	Pending
7.	NW Sumatra, Indonesia	Pacific Indonesia LNG Co.	CP74-160, 14/	Port Hueneme, Calif.	620	226	1979 (20 years)	Pending

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1/ As specified in the initial applications filed with the FPC; additional details, including revisions which may have been made subsequent to the initial filing, are contained in each of the listed docket files.

2/ Related Docket Nos.: Distrigas Corp. CP72-165, CP72-167, CP72-168, CP73-135, CP73-330, CP74-227; Distrigas Pipeline Corp. CP73-148, Distrigas of New York Corp. CP73-230, CP74-122; Distrigas of Massachusetts Corp. CP74-137; Algonquin Gas Transmission Co. CP72-132.

3/ Related Docket Nos.: Columbia LNG Corp. and Consolidated System LNG Co. CP71-289.

4/ Related Docket Nos.: Columbia LNG Corp. and Consolidated System LNG Co. CP71-289; Consolidated System LNG Co. CP71-290.

5/ Related Docket Nos.: Southern Energy Co. CP71-264.

6/ Related Docket Nos.: Eascogas LNG, Inc. CP73-88, Algonquin LNG, Inc. CP73-139; Algonquin Gas Transmission Co. CP73-197; New England LNG Co., Inc. CP73-199; Distrigas Pipeline Corp. CP73-148; Distrigas of New York Corp. CP74-122.

7/ Related Docket Nos.: Distrigas Corp. CP74-227; Distrigas Pipeline Corp. CP73-148; Distrigas of New York Corp. CP73-230, CP74-122; Distrigas of Massachusetts Corp. CP74-137.

8/ Withdrawal pertains only to the applications for import (CP73-132) and resale (CP73-230).

9/ Related Docket Nos: El Paso Eastern Co. CP73-259; El Paso Natural Gas Co. CP73-260.

10/ Related Docket Nos: Transco Terminal Co. CP73-268; Transco Energy Co. CP73-269; Transcontinental Gas Pipe Line Corp. CP73-270.

11/ Related Docket Nos: Southern Energy Co. CP73-272; Southern Natural Gas Co. CP73-273.

12/ Related Docket Nos: Consolidated System LNG Co. CP73-283.

13/ Related Docket Nos: Trunkline LNG Co. CP74-138; Trunkline Gas Co. CP74-140.

14/ Related Docket Nos: Pacific Indonesia LNG Co. CP74-207; Western LNG Terminal Co. CP75-83-3.

STATEMENT OF

LEONARD W. FISH

SENIOR VICE PRESIDENT
AMERICAN GAS ASSOCIATION

Before the

SUBCOMMITTEE ON ENERGY AND POWER
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE

of the

HOUSE OF REPRESENTATIVES

January 27, 1976

STATEMENT OF

LEONARD W. FISH

SENIOR VICE PRESIDENT
AMERICAN GAS ASSOCIATION

Before the

SUBCOMMITTEE ON ENERGY AND POWER
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE

HOUSE OF REPRESENTATIVES

January 27, 1976

Mr. Chairman and members of the subcommittee:

My name is Leonard W. Fish and I am a Senior Vice President of the American Gas Association. My areas of responsibility for A.G.A. include planning, statistical services, gas supply and market analysis. I am accompanied by Mr. Robert Ciliano, Project Manager, Regional and Environmental Studies Group; Mathematica, Inc. Mr. Ciliano is here because he was personally involved in the development of A.G.A.'s energy model and should there be any specific, technical questions about the mathematical interrelationships or assumptions inherent in the model design, he is better qualified to answer them than I am.

A.G.A. represents some 300 natural gas transmission and distribution companies which supply over 85% of the utility natural gas sold in this country. The gas industry delivers gas to an estimated 150 million consumers through a one-million mile pipeline network. The natural gas industry is the nation's sixth largest with an investment of some $50 billion in that pipeline system and related facilities.

While some of our members own producing gas wells (accounting for approximately 6% of the production in the United States), none of them are primarily engaged in the production of oil and gas, and all of them are regulated public utilities serving franchised service areas under certificates of public convenience and necessity.

Since A.G.A.'s member companies are distributors and transmitters of natural gas, there is no benefit to them to create or perpetuate a notion of a gas shortage. Quite the contrary, the fact of the gas shortage is being used against these companies by competitors in selling energy (whose supply difficulties, although as great or greater in some cases, are not as well advertised), their ability to achieve the financing necessary to seek and provide increased supplies is severely impared, they cannot serve customers they have sought for years, and indeed are forced into the unfortunate position of curtailing deliveries and allocating sales among existing customers. Further, as less and less gas is available it decreases the efficiency of operation of their transport facilities.

Our transmission companies provide the most efficient means of long distance energy transportation. Our utility distributors are in the unique position of dealing on a daily basis with the end-use consumer - whether he be the home owner, whether he be the school, hospital, bakery, or public building, or whether he be the industrial user who provides our jobs and the consumer products we need. We know his problems and his concerns. They are our problems and our concerns. It is the natural gas supply shortage which causes our industry and our customers these concerns which are great and growing. It is this shortage and its solution which we would like to address today.

In my statement, I intend to cover three subjects.

First, I want to describe the purpose for A.G.A.'s development of a national energy model and how the model is designed.

Second, I will illustrate how we use our model to show the effect of new gas deregulation on gas supply.

And, finally, I will discuss our assessment of the economic impact on the consumer of continued gas regulation compared to deregulation of new gas supplies.

TERA: BACKGROUND AND PERSPECTIVE

Program Objectives

TERA (Total Energy Resource Analysis) is a computerized simulation capability designed to assess the impact of the many factors influencing the energy industries. Among these influences are economic, technological, environmental, regulatory, competitive and public policy considerations whose simultaneous interaction can serve to alter the energy supply/demand balance in a complex and, in some instances, dramatic fashion.

The TERA model began its development in early Spring, 1971 under the auspices of the American Gas Association Planning Division and sponsorship of the A.G.A. Research and Communication Committee. The objectives of the program were multi-faceted but essentially hinged upon gaining the capability to study policy issues relative to:

- Forecasting total and fuel-specific energy demands on a regional basis;

- Forecasting gas supply and reserve levels;
- Evaluating supply-demand interactions at both the national and regional levels;
- Evaluating the impact of various economic, demographic, environmental, technological and regulatory factors on the energy industries;
- Analyzing alternative assumptions regarding interfuel competition; and
- Providing a continuously up-to-date data bank.

Three rather unique features of this effort which have remained intact since TERA's inception are:

(1) the empanelment of an Advisory Committee comprised of gas industry technical personnel to advise and monitor the development effort as well as assess the need for periodic system revision and expansion;

(2) the concept of a "Base Case" to serve as a framework for scenario building, sensitivity analysis and parametric assessment related to special studies and policy evaluations; and

(3) the provision for "scheduled maintenance" at six-month intervals wherein data and information updates are routinely conducted, minor model revisions and "tune-ups" performed, and the dissemination of output and system related documentation to member companies initiated.

Overview of Model Structure

The TERA system is highly modularized and consists of seven major components, a data base, master data file and command files. These are briefly described below:

Major Program Components

(1) Demand Forecasting Module. This portion of the system provides forecasts of total demand for energy as a commodity, nationally and regionally, by major consuming market sector (e.g., residential, commercial, industrial[1], etc.)

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[1] Recent system refinements have extended the industrial sector disaggregation to the 2-digit SIC level.

(2) Fuel Market Shares Module. This portion of the system estimates those proportionate shares of each end-use market's energy requirements which would be met by each fuel type in the absence of any supply restrictions.

(3) The Gas Supply Module. This portion of the system is comprised of both onshore and offshore sub-components. In these models, gas, oil and liquids prices; exploration, development and production costs; leasing, royalty, taxation and other policy variables; as well as resource base and technological parameters are translated into relative risk-return measures which determine the amount of exploratory drilling to be anticipated and the resultant addition of new gas and oil supplies into proven inventories. The time-phased appreciation via extension and revision of these "proven reserves" is also modeled.

(4) The Wellhead Pricing and Production Module. This portion of the system translates the sequence of new reserve additions into attainable production levels for any given year of simulation. Moreover, this module computes the constantly changing weighted average wellhead price of domestically produced gas in the following manner. Any given year's production level can be considered to be the aggregated contribution of production volumes from past reserve dedications or "vintages", for each of which an average new field market price is specified. Moreover, each of these new price levels is escalated over time via either (a) a fixed annual increment; (b) a fixed annual percentage; or (c) a percentage of each year's prevailing new market price.[1] While the offshore Gas Supply Model is basin specific, the Onshore Model produces only aggregate lower 48 supply estimates which may (at the user's discretion) be apportioned to various producing districts.

(5) The Supply-Demand Interaction Model. This portion of the system recursively iterates over a series of trial allocations in an attempt to balance gas supply and demand by market sector, by region. In addition to domestically produced gas, up to twelve supplemental sources may be considered as well (e.g., SNG, coal gas, Canadian and Mexican imports, advanced fracturing, etc.). The user specifies his preference among a host of alternative decision rules which guide how much (or how little) of

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[1] This greatly facilitates policy analysis with regard to issues such as partial or phased deregulation, total deregulation, etc.

each supply source may be routed to each region and the context of its usage (e.g., base load, peak-shaving, etc.). The model attempts to satisfy these rules to the greatest extend possible and a trial allocation is made. The pricing model then "costs out" this allocation to determine the actual "rolled-in" price of gas consumed by each sector in each region. A consistency check is then made via the total demand and market share models to see to what extent the pre-allocation demand levels would be modified given the post-allocation retail price computations. If this difference exceeds some small "tolerance level" (e.g., a change of 1%), a reallocation is made with the new demands and so on recursively until the system converges to either a condition of gas supply-demand balance or irreconcilable shortfall. If the latter case prevails, a curtailment procedure can be followed in which each consuming sub-sector in each region is "cut back" in a specified sequency, but within certain maximum and minimum bounds until the "excess demand" is completely erased.

This model is particularly useful in examining curtailment and emergency allocation scenarios and policy issues.

(6) The Retail Pricing Module. As alluded to above, this model converts wellhead into city gate and then into sector-specific retail prices given various assumptions concerning transmission costs, cost of service mark-ups, etc. All pricing includes the cost of supplementals on a "rolled-in" basis. Incremental pricing is currently not considered.

(7) Report Generators. These utility programs simply display the outputs of the respective modules in a variety of special report formats to permit either concise summaries or full-detail print-outs.

The Data Base. The TERA Data Base contains literally hundreds of time series and cross-sections of consumption, price, cost, demographic, income, and many other types of information. These data represent information used in the estimation and formulation of the relationships embodied in TERA and is not a necessary portion of any simulation input data at execution time.

The Master Data File. This data file contains the thousands of pieces of information required by the program at execution time to perform a simulation and consists of initial values, user selected options, price, cost and policy data among other important parameters.

The Command File. This file may be thought of as an "exception file" for scenario building. That is, if unaltered, a simulation will be conducted using the information contained in the Master Data File which is always automatically pre-set to conform to the current version of the TERA "Base Case" (see below). If a user wishes to examine special scenarios, he places into the Command File those variable changes (e.g., prices, lease schedules, etc.) which conform to the conditions of the sensitivity study to be performed. To examine several "off-Base Case" scenarios, one needs only to construct their corresponding Command Files, leaving unaltered the vast portion of the Base Case input contained in the Master Data File.

The TERA Base Case: Input and Output

During the development and implementation of the TERA model, a "base case" was defined representing the industry's "most likely" forecasts of energy supply and demand related input parameters based on the "most reasonable assumptions" regarding the major factors influencing the energy industries. These factors include:

(1) Economic factors such as GNP growth, industrial growth and personal income;

(2) Demographic factors such as population, household formation, etc.;

(3) Technological factors such as new resources of energy, new uses of energy, new techniques for drilling, etc.;

(4) Government policy including wellhead price, depletion allowance, import quotas, pollution standards, etc.; and

(5) Competitive strategy by other energies including the coal, oil and electric power supply sectors.

Of course, associated with the Base Case Input assumptions at any given time must be a unique set of resultant outputs which are termed "The Base Case Output." It is this documentation (along with special study reports) which is disseminated at periodic intervals to member companies.

The Use of TERA for Policy Analysis: Ground-Rules, Boundaries and Limitations.

While the lattitude is great, indeed, for utilizing TERA for a variety of policy analyses, it has, like every model, its application boundaries and limitations. One such limitation, for example, is that supply functions for gas competitive fuels are not estimated. Thus, for example, in the Supply-Demand Interaction Model the tacit assumption after balancing apportioned gas supplies with demands is that sufficiently abundant quantities of other fuels will be available to fill the breach in those curtailed sectors and regions. Because the supply functions of these competitive fuels are not explicitly modeled, there is no feedback effect upon their respective price levels. Without this, of course, no simultaneous total energy balance can be performed within the system at present.

Nonetheless, the art of applying the model rests in the capacity of the user to translate selected parameters among the numerous variable inputs and option codes into values that correspond to the scenario he wishes to examine. In some instances, this procedure may be very straightforward, such as simply varying price levels. In other cases (such as, for example, choosing a set of sector-specific curtailment priorities and cut-back ratios which realistically describe a proposed FPC allocation policy) considerably more skill is required. In general, however, TERA provides the capability to examine policy issues critical to the industry and nation such as the following.

(1) assess comparative effects of alternative field prices, cost and leasing levels on new reserve additions and volumes;

(2) examine the effect of competing fuel prices on gas demands and gas supply shortfalls;

(3) analyze the impact of the availability and prices of supplementals on gas supply and demand;

(4) analyze the impact of proposed emergency allocation policies upon regional gas deliveries and curtailments; and

(5) assess the impact on the supply/demand balance of alternative wellhead pricing schedules, the results of which could be used to arrive at a realistic behavior of the deregulated gas supply market.

INCREASED GAS SUPPLIES RESULTING FROM NEW GAS DEREGULATION

A.G.A. TERA model has been used to study a variety of parameters for their effect on natural gas supply and demand. Primary interest, lately has been on the reaction of natural gas supplies to increasing wellhead prices for new gas. However, it is also important to recognize that gas supplies can be influenced by other variables such as variations in offshore acreage leased each year, physical limitations on the amount of drilling which can be accomplished, tax policies, etc.

Since the issue before us today is deregulation, the quantitative discussion in this section of my statement will be limited to the effect of higher prices for new gas.

As indicated earlier, TERA is basically a simulation model, rather than an optimization model. That is, it calculates the quantities of natural gas made available at assumed pricing conditions and the economic demand commensurate with those prices, rather than attempt to calculate a "market clearing" price, or the price at which supply and demand balances. This procedure offers the user the primary advantage of being able to see the effect of changes in his input assumptions on supply and demand separately.

Three scenarios will be presented in this statement, each extending out to 1985:

- continued regulation
- deregulation of new gas at two price levels

For these sample scenarios, the following gas price assumptions were made:

- all prices are in constant 1976 dollars (no inflation assumed)
- with continued regulation, the wellhead price of "new" interstate gas will increase 1¢/MmBtu/yr. in constant dollars starting at 52¢/MmBtu in 1976
- for deregulation, two price levels were examined, $1.50 and $2.00/MmBtu for new interstate natural gas.

The supply of conventional natural gas produced with these scenarios in the lower-48 states is shown in Table I.

TABLE I

Conventional Natural Gas Supplies
available for sale
(excludes Alaskan gas, imports
& supplementals)

- Trillion Cubic Feet -

	1976	1980		1985	
Continued regulation	17.2	15.5		12.5	
Deregulation:					
New gas price		1.8	2.7	4.0 TCF	6.0
$1.50	17.9	17.3		16.5	
$2.00	18.0	18.2		18.5	

A brief explanation of the absolute level of these supply figures is warranted. Gas supply has a variety of definitions. For example, for 1974 the U.S. Bureau of Mines reported natural gas "Gross Withdrawals" of 22.8 trillion cubic feet (Tcf); after repressuring, a "Net Production" of 21.8 Tcf is reported; after losses and waste, a "Marketed Production" of 21.6 Tcf is reported; and, after field use, net change in underground storage and loss in transmission, a "Net Marketed Production" of 18.9 Tcf is reported. Our figures can be related to the net marketed production for comparison purposes.

In addition, we recognize that biases can, and often do, exist in computer simulations. However, since these biases tend to be the same for each run, the differences between two runs is usually quite reliable. In other words, we firmly believe that under our pricing assumptions, 6 Tcf additional natural gas can be made available in 1985 over the case of continued regulation, even though the actual value for total natural gas available under continued regulation might vary from the indicated figure.

These studies show that significant new quantities of natural gas can be made available through deregulation of new gas. Moreover, as the deregulated price increases, additional quantities of gas are found and produced.

IMPACT OF NEW GAS DEREGULATION ON THE CONSUMER

Within the industry and government, there is little, if any, disagreement with the conclusion that higher prices will bring forth greater quantities of gas. Unfortunately, there are some differences of opinion on the actual supply price elasticity; that is, how much gas will be found and produced at a given price increment. There is even less unanimity on assessing the impact of these higher gas prices on the consumer.

The assumptions that the investigator makes about the price level of deregulated gas and the interchangeability of fuels often predetermines the results of the impact calculation. For example, if one assumes that the average price of all quantities of natural gas will be priced at parity with oil and, further, that the user can freely switch fuels, then, by definition, the impact on the consumer will be zero - the cost of gas or oil will be equal.

The logic has also been presented that even if regulation is continued, there will be some new gas found and produced. The quantity may be woefully inadequate, but there will be some new gas to be sold at regulated prices. However, if new gas is deregulated, this same increment of new gas will be sold at the higher price realized for all the new gas discovered. To some people, this represents a consumer "debit" for deregulation.

The logic may be sound but it is based on false and shakey assumptions. The first assumption is that gas and alternate fuels are freely interchangeable in all markets - which is not true. The second assumption is that deregulated gas prices will reach parity with oil - which has not been proven.

It is also important to remember there is an international economic impact to consider. Clearly, in the future, the country will use all the domestic fuel economically available at any point in time; any deficiencies must be made up with imported oil. Therefore, any loss in natural gas availability by perpetuating regulation will increase our imported oil requirements and increase foreign payments.

In our studies of consumer impact, we have looked at the different market sectors and at the two new gas prices discussed in the previous section of this statement.

Calculating the debits or credits to the consumer resulting from new gas deregulation must include the cost of natural gas, and the cost of providing equivalent energy service with some other fuel if adequate gas is not available because of continued regulation. This latter point is especially important because all fuels are not freely interchangeable. For example, in the residential market, the all-gas home cannot be converted to an all-oil home. Oil can be used for heating but electricity would have to be used for cooking, water heating and clothes drying. Switching from gas to electricity incorporates significant thermal inefficiencies and cost debits.

The average annual gas appliance consumption is as follows:

home heating	110.0	million Btu
cooking	10.5	
water heating	27.5	
clothes drying	4.5	
Total	152.5	million Btu

If we assume that natural gas would be replaced by oil for heating and by electricity (generated by oil) for the other three functions, the primary fuel energy consumption of the house would become:[1]

home heating	122	million Btu
cooking	18	
water heating	66	
clothes drying	15	
Total	221	million Btu

On this basis, the loss of 1 Tcf of natural gas production would require 1.44 Tcf of "oil equivalents" for replacement. Thus, a 1980 gas "deficiency" of 2.7 Tcf would require importing 465 million barrels of oil on an equivalent energy replacement basis but would require importing 670 million barrels to provide equivalent service to the residential market. At $12/B, the higher figure would cost 8 billion dollars

The direct impact on the consumer would also be significant. The annual gas cost for the all-gas home in 1980 would be about $420. The energy cost for the combination oil-electric home would be about $695. If electricity is also used for heating, the annual energy cost would be $1125. Since 2.7 Tcf of natural gas could serve 16.4 million homes, the total cost to the consumer for "equivalent" service could total 12.3 billion dollars for combination oil-electric service, (and nearly 20 billion dollars for the all-electric case).

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[1] Appliance efficiencies: The Rand Corporation, "California's Electric Quandry. Vol III"

I leave it to others to decide exactly how much of the new supplies of gas brought forth by new gas deregulation will find its way into the residential (or commercial) market, but clearly, deregulation of new gas can offer a considerable saving to the consumer and in 1980 can reduce our foreign payments for oil by as much as 8 billion dollars.

The tables below summarize the costs to the consumer for energy under regulation and new gas deregulation for the conditions noted. Our analysis looks at the costs from a total energy perspective, i.e., energy demand will be met either in the form of natural gas or alternate fuels.

TABLE II

Comparative Aggregate Consumer Energy Costs
Deregulated new gas = $1.50/Mcf

	Billion Dollars/yr.		
	1976	1980	1985
Deregulation of new gas	24.0	28.1	31.3
Continued regulation:			
Gas deficiency made up with			
all oil	23.0	32.7	36.3
combination oil-electricity[1]	24.2	36.1	44.1
all-electric[1]	25.9	41.2	55.9

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[1] (Note: electric prices used in the calculation of electric costs were taken from forecasts in Electrical World magazine, September 15, 1975.)

TABLE III

Comparative Aggregate Consumer Energy Costs
Deregulated new gas = $2.00/Mcf

	Billion Dollars /yr.		
	1976	1980	1985
Deregulation of new gas	25.3	35.6	43.1
Continued regulation:			
Gas deficiency made up with			
all oil	23.3	35.5	42.4
combination oil-electricity[1]	24.7	40.6	54.1
all-electric[1]	26.6	48.2	69.7

The results of our studies show that the consumer will benefit economically from deregulation of new natural gas. The only case showing even a small penalty to the consumer is the unlikely situation where new gas is assumed to cost $2.00/Mcf and oil is assumed to satisfy all gas shortages on an equal Btu-for-Btu basis.

It is more likely that gas will be used in priority markets where its advantages would bring maximum benefit to the consumer. If deregulation of new natural gas prices results in increased quantities of gas available to the homeowner, the economic benefits are gratifyingly large. A savings of up to 13 billion dollars in 1980 and up to 26 billion dollars in 1985 is probable.

We did not attempt to estimate costs for converting existing gas-fired equipment to other fuels, if gas is unavailable. This cost could be large, however, and would be an additional credit for deregulation.

The environmental advantages of cleaner burning natural gas are also well known and would increase the economic advantage for deregulation.

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[1] (Note: electric prices used in the calculation of electric costs were taken from forecasts in Electrical World magazine, September 15, 1975.)

SUMMARY

- A.G.A. has developed an effective energy model, TERA, which can be used to study the effect of a wide variety of economic parameters and policy issues on the supply and demand for natural gas.
- The model predicts that significant new quantities of natural gas can be made available by deregulating the wellhead price of new gas.
- Deregulation of new gas benefits the consumer economically and can reduce our nation's requirement for imported oil.

Testimony of Robert S. Pindyck
Massachusetts Institute of Technology
on

"THE BEHAVIOR OF NATURAL GAS MARKETS UNDER DEREGULATION"

before the House Committee on Interstate and Foreign Commerce
Subcommittee on Energy and Power
January 27, 1976

Four months ago I testified before this Subcommittee on the likely effects of several emergency proposals that were being considered to deal with natural gas shortages this winter and next.[1] I think that it was fairly well recognized by this Subcommittee at that time that shortages of gas were very much the result of past and present regulation of the ceiling price of natural gas. I also think that many of you have recognized that recent and current shortages need not have occurred. Had natural gas field prices been allowed to rise by moderate amounts in past years, we would not be faced with shortages this winter and in the winters to come. I think that it is also becoming clear that the benefit to consumers accruing from lower (regulated) prices is outweighed by the loss resulting from the inability of many consumers to obtain gas at all, as well as the loss resulting from a lower GNP and level of employment that necessarily occurs as a side effect of a resource shortage.

I pointed out in September that although emergency measures (such as reallocating gas from intrastate to interstate markets) could help ameliorate some of the effects of a shortage, but would certainly not deal with the basic long-term problem. A continuation of present regulatory policy will result in an ever-growing shortage of natural gas, and the situation will eventually be such that no emergency allocation programs would be able to deal with it. I am happy, therefore, that this Subcommittee is now seriously considering policies to deregulate the natural gas industry, and in so doing to deal with the long-term problem.

I would like to begin today by reviewing the status of the natural gas industry and the effects of regulatory policies, as well as to consider what price levels we might expect as a result of deregulation. I will then discuss the issue of supply response in more detail, namely whether higher gas prices are likely to elicit increased supplies of natural gas over time. This is an important issue, and I realize that many critics of deregulation are concerned with the extent to which higher prices will result in higher supplies of gas. Finally, I will discuss the question of consumer costs and benefits from deregulation.

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[1] R. S. Pindyck, "Emergency Proposals to Deal with the Natural Gas Shortage," Testimony before the House Subcommittee on Energy and Power, September 24, 1975.

The Effects of Regulatory Policies

It is important to have a quantative assessment of the impact of deregulation as well as of alternative regulatory policies. To this end I will draw upon the econometric model of the natural gas industry developed at the M.I.T. Energy Laboratory by Paul MacAvoy and myself. This model, which was constructed under the financing of the National Science Foundation through Grant #GI-34936, involves fitting economic relationships to historical data on a regionally disaggregated basis. By performing computer simulations with the model under alternative regulatory price policies, one can simultaneously account for the impact of these policies on all aspects of the industry, including the exploratory process and reserve accumulation, the production of gas out of reserves, the distribution of gas through the pipeline system, and the demand for gas in consuming regions. The model has already been used as a means of forecasting the likely impact of alternative policies, and I used it last September to evaluate the emergency proposals that this Subcommittee was studying at the time.[2]

On June 26, 1974 the Federal Power Commission allowed new gas (i.e. gas produced from wells after January 1973) to sell at a price of 50¢ per mcf. This uniform national rate increased by about 5¢ in 1975, and according to indications from the FPC, would increase by approximately 2¢ per annum over the next few years. It is probable that the FPC realized that these prices would not be sufficient to clear natural gas markets. Predictions made using the econometric model at M.I.T. indicate that a continuation of this policy would result in steady increases in excess demand, so that by 1980 excess demand would exceed eight trillion cubic feet. Furthermore, this excess demand would not be spread evenly across the country, but would be concentrated in the North Central and Southeast regions of the country, and to a lesser extent in the Northeast and West. In some states excess demand could reach 60% or more of total demand by the end of this decade.

Recently the FPC revised the "just and reasonable" rate for "old" gas, i.e. for gas flowing in interstate commerce prior to January 1, 1973.[3] As of January 1 of this year, a base rate of 23.5¢ per mcf is allowed on "old" gas, and this rate will increase to 29.5¢ per mcf on July 1, 1976. These rate increases will have some impact on natural gas shortages, although the impact will work more through the demand side than on the supply side, since raising the price of old gas provides less of an incentive for additional exploration and discovery of reserves. We have not used our econometric model to simulate the impact of this new FPC decision, but I would guess that doing so would result in a forecast of excess demand for 1980 of seven trillion cubic feet rather than eight.

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[2] The model and its application to policy analysis is described in considerable detail in P.W. MacAvoy and R.S. Pindyck, The Economics of the Natural Gas Shortage (1960-1980), North-Holland Publishing Co., Amsterdam. A shorter description can be found in Price Controls and the Natural Gas Shortage, by the same authors, and published by the American Enterprise Institute in Washington, D.C.

[3] FPC Opinion #749, Docket #R-478.

The situation, then, is still severe, and unless an incentive is provided for the exploration and discovery of new reserves, we will be faced with growing natural gas shortages. Such an incentive would be provided by the deregulation of "new" gas. I feel that such a policy would result in increased exploration and discovery, and, after two or three years, significantly increased production of gas. Average wholesale prices would rise over time (as a growing percentage of total gas production became "new" gas), and this would help reduce demand. The net result would be a reduction and eventual elimination of natural gas shortages.

An important question, of course, is how high prices would rise as a result of a deregulation of "new" gas. Our work at M.I.T. so far indicates that these prices would rise by about 50¢ with further increases of about 5¢ per annum.[4] These price increases are really not very large, particularly considering the fact that retail prices for consumers in the northern part of the United States are on the order of $1.75 or more.

Supply Response Under Deregulation

The econometric model developed at M.I.T. is an excellent vehicle for analyzing the supply response to deregulation. The time-dynamics of the different stages of reserve accumulation, production, as well as demand, are an important aspect of the model. Policy questions center on not only how much production will be forthcoming at higher prices, but also on how long it will take for the effects of higher prices to occur. The model describes in considerable detail the accumulation of both natural gas and oil reserves. Reserve additions are broken down by new discoveries, extensions, and revisions of previous discoveries. New discoveries are explained, first, by determining the number of exploratory wells that will be drilled in response to natural gas and oil prices, as well as to drilling costs and geological conditions. Then, success ratios and sizes of finds are determined, so that new discoveries of natural gas can be forecasted by multiplying the forecasted number of wells drilled by the success ratio for gas discoveries and the average size of find for gas discoveries. New discoveries of oil are similarly determined. The model accounts for directionality in drilling (i.e. between oil and gas), as well as shifts to higher risk drilling that could occur in response to higher prices. The model also accounts for the effects of depletion, and predicts how the size and number of new discoveries would shift over time as potential reserves are exhausted. Finally, the model explains how the production of gas depends on both reserve levels and price. This is important in separating short-term supply response (occuring directly from the impact of higher prices) from longer term supply response (occuring indirectly as higher prices result, over time, in reserve accumulation).

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[4] Our econometric model was originally constructed using data through 1972. The National Science Foundation is now supporting an updating and revision of the econometric model so as to include the 1973 and 1974 data which is now available. This updating is not entirely completed, and therefore the estimates and forecasts that I am presenting here are based on preliminary statistical results.

The discovery and production of natural gas in off-shore regions is treated separately in the econometric model. There are now, for geological and economic reasons, high probabilities of finding large discoveries off-shore. As both gas and oil prices increase and more off-shore acreage is leased by the Federal government, these regions will probably provide an increasing share of gas production. Off-shore reserve accumulation and production are explained separately in the econometric model since these variables respond to different economic and engineering conditions from those on-shore. For example, drilling costs are higher off-shore, and off-shore leasing procedures of the Federal government do not apply to privately owned on-shore land.

As I mentioned before, if new gas were deregulated, I would expect its price to rise by about 50¢ initially and about 5¢ per year thereafter. Our econometric work indicates that we could expect the following supply response as a result of these higher prices. First, there would be a short-term gain of about 1.5 trillion cubic feet of additional production within the first year. This would not result from the accumulation of new reserves, but rather from a higher production level out of existing reserves in response to the higher prices. By 1980, however, the effects of increased exploration and reserve discovery would be significant. The higher prices would result in about 3.5 trillion cubic feet of additional supply. Combined with a 3.5 trillion cubic foot reduction in demand (from what it would be otherwise), there would be no shortage of natural gas.

Much of this supply response would be from off-shore regions, particularly in later years. Under existing regulatory policy, we would predict for 1980 a total natural gas reserve base of about 40 trillion cubic feet in the Gulf of Mexico. Under the higher prices mentioned above, reserves would instead be 50 trillion cubic feet. By 1985 the difference would be even more significant, with an off-shore reserve base of 54 trillion cubic feet under existing policies and 72 trillion cubic feet under deregulation. The larger reserve base would, of course, result in a higher level of production. In 1980 off-shore production would be 5.1 trillion cubic feet under existing policies and 6.4 trillion cubic feet under deregulation, while in 1985 production would be 7.4 trillion cubic feet versus 9.9 trillion cubic feet.[5]

We see, then, that higher prices would indeed result in an increase in supply. We found in our econometric work that one of the ways by which this happens is through a shift towards higher risk drilling. Drilling in relatively unexplored areas is likely to result in discoveries of much larger size. However, the risk is also considerably greater, and would often not be warranted under existing low price levels.

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[5] These numbers are based on the assumption that the Bureau of Land Management leases two million acres per year in the Gulf of Mexico.

We find also that depletion of the potential reserve base becomes a factor by around 1985 or 1990. And at this time success ratios and discovery sizes begin to fall somewhat as less potential reserves are available to be discovered. Most of this depletion, however, will occur in on-shore regions, and certainly does not provide a reason to continue regulation. We can expect that fifteen years from now significant discoveries of off-shore gas will be available, as will alternative sources of energy.

Costs and Benefits of Deregulation

There is no question that there is a direct cost to consumers from deregulation - prices will indeed rise. It is important to stress, however, that without deregulation many consumers will not obtain gas at all. Thus, the cost of higher prices to some consumers must be balanced against the gain to other consumers who without higher prices would not be able to obtain gas. Since the demand for natural gas is fairly inelastic relative to other consumption goods (i.e. most consumers who want gas are willing to pay even higher prices for it), this gain to consumers is likely to be quite large, and in fact almost equal to or larger than the cost. Thus, although some consumers would "lose" under deregulation (by having to pay higher prices), a large number of consumers would gain, and the net effect could be positive.

This does not even consider the indirect benefits from deregulation. A growing shortage of gas resulting from continued regulation would have depressing effects on industrial activity, aggregate production, and employment. The effects would be similar to those that would occur if we imposed a permanent oil embargo upon ourselves. There is thus an indirect benefit from deregulation that would be quite significant.

Summary

Continued regulation of natural gas will result in growing shortages. The cost of these shortages will be significant, as many consumers are unable to obtain gas, and as supply restrictions have their usual depressing effect on the economy. It is therefore important that a policy to deregulate natural gas markets be implemented. Deregulation would result in price increases that would be moderate, and in significant increases in supply.

Statement of
Robert A. Hefner III
Independent Producer
Oklahoma City, Oklahoma

COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
UNITED STATES HOUSE OF REPRESENTATIVES
January, 1976

I am a petroleum geologist and independent producer from Oklahoma who has devoted more than fifteen years to natural gas exploration in the Hugoton/Anadarko Province, the largest natural gas producing area1/ in the United States. I believe that what I have to say today will help you to navigate the maze of controversy surrounding the question of gradually ending wellhead price controls for natural gas as proposed by the Krueger Bill (H.R. 10480). This Bill will allow me and the rest of the producing industry to rapidly proceed with exploration and development of our onshore natural gas reserves.

I have closely followed and participated in the Senate's debate and recently have seen that the most troubling issues in the Senate are the same as in the House; i.e., (1) the producers' failure to bring forth gas at regulated prices, (2) the resource base, (3) competition, and (4) price/supply relationships. Based upon my own experiences, I believe I can resolve your concerns regarding deregulation of natural gas.

The Producers' Failure to Deliver Gas at Regulated Prices

The Green Story

The No. 1 Green, a wildcat well, is located in the center of the Hugoton/Anadarko Province (as I mentioned before, the largest natural gas

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1/ Cumulative production of 31.4 trillion cubic feet of gas. International Petroleum Encyclopedia, 1975.

producing area in the United States). The story of the No. 1 Green illustrates a most important fact: it has not been and is not now a question of "holding gas off the market" but rather a question of being able to afford to initiate new projects of substance at regulated prices.

The geological work which led to the No. 1 Green began in 1959, with seismic testing and lease acquisition commencing in 1962. My company was unable to raise sufficient funds to commence drilling until 1967. After two years of drilling and overcoming immense technical difficulties, the Green was completed as a natural gas producer in 1969. Not only was this well the second deepest ever drilled in the world -- 24,452 feet -- it contained the highest pressure ever recorded at that time at the surface of the ground -- 15,150 psi. Temperature at the bottom of the well is 400 degrees Farenheit. One piece of equipment, the wellhead, cost over $125,000 and would cost over $250,000 to replace today. This one expenditure was more than the total cost of an average depth gas well drilled in this Province in the 1960's.

Because of the enormous pressure encountered in the No. 1 Green, the well was out of control for six weeks. Over $65,000 was spent for mud in just one day (at a cost of $22.00 per barrel) in the attempt to bring the well under control.

Eventually, the many technical and mechanical problems were solved and, in so doing, natural gas drilling technology was advanced far beyond where it had ever been. However, the total cost was more than $2,000,000 over the original estimate. In all, the No. 1 Green cost $6,500,000 to complete. This figure included $2,000,000 for leases, geological and geophysical work.

The No. 1 Green is no ordinary well. It is very deep, extremely expensive and has already produced the equivalent of over a million barrels of oil. Were it not for Federal price controls, we could have had many more wells like the No. 1 Green on the line years ago.

We tried during those years to raise money from every available source -- banks, producers, natural gas pipelines, distribution companies, and individuals. We are still trying to raise money. The reason we had difficulty raising money then is the same reason we are having difficulty raising money today -- a regulated price and its inherent uncertainties.

It was seven years from the time we purchased the first lease to the time we received our first income from the No. 1 Green. In January, 1970 we signed a 20-year contract to sell the gas in interstate commerce at a price of 21 cents per Mcf with allowance for a one-cent per Mcf increase every five years and no renegotiation -- an incredibly poor settlement for a $6,500,000 investment. The "cost" of that gas is $3.06 per Mcf using the Federal Power Commission Opinion 699-H cost methodology and a twenty percent rate of return (which was found to be just and reasonable for Small Producers by FPC Opinion 742). The cost with no return on capital is 87.68 cents per Mcf. (See Appendix A & B)

This story of the No. 1 Green should assist you in understanding why consumers have been denied the benefits of natural gas which we have yet to discover and produce.

Using FPC cost methodoly, the "cost" to develop Oklahoma's natural gas reserves lying between 15,000 and 30,000 feet is as follows:

Depth Range	Cost at 14.73 psia (¢ per Mcf)	Cost at 14.73 psia[3] (¢ per Mcf)	Cost at 14.73 psia[4] (¢ per Mcf)
15,000'-17,499'[1]	66.25	94.26	112.95
17,500'-19,999'	78.00	113.09	136.49
20,000' & Over	94.73	139.83	169.91
20,000'-22,499'[2]	130.69	183.27	224.21
22,500'-24,999'	149.76	230.22	282.89
25,000'-27,499'	175.13	272.21	235.38
27,500'-29,999'	206.99	323.97	400.09
30,000'-32,499'	243.12	383.64	474.67

1/ Nationwide average costs from 1972 JAS data.
2/ GHK/Gasanadarko median costs from actual cost data.
3/ Costs recognizing 60% increase in drilling cost since 1972.
4/ Costs recognizing 100% increase in drilling cost since 1972.

Realizing all of this I am sure there are those of you who would suggest that I petition the Federal Power Commission for special relief. That has been shown to be an unworkable alternative. In 1974, for example, the FPC came up with a decision in which the rate set did not even provide for the return of investment, much less a return on capital.[2] Often, it takes about a year for the FPC to reach a decision on a special relief application.[3] Even then, litigation could take several years, after which the decision is often remanded back to the Federal Power Commission for further consideration.[4] Of course, the decision could be negative or, after more than a year of proceedings, the producer may get no answer at all.

All of this should make clear that it is absurd to think that any system of regulated prices can guarantee producers a return on investment! Our story of the No. 1 Green should also clarify why the costing technique in any rate system is arbitrary and inappropriate to the realities of field operations.

[2] Terra Resources, Inc. (Operator), et al. (1974) 51 FPC 876.

[3] Sun Oil Company, Docket No. RI 75-6; July 2, 1974, initial application filed; October 6, 1975, FPC Opinion.

[4] George Mitchell & Associates, Opinion No. 649; Petition filed, August 11, 1972, District of Columbia Court of Appeals remanded the case to the Federal Power Commission on September 19, 1974.

Furthermore, within the regulated system, substantial capital risks (as opposed to investments) cannot be taken because the price ceilings represent an average cost, which means that roughly half the gas being produced today costs more than producers are allowed to receive for it. In addition, the "cost" figure is manufactured from past drilling experience and, as drilling costs perforce increase over time, the FPC regulated price ceiling is inadequate for projects. If you are operating in the past -- you cannot, within a risk industry, proceed to the future!

When I anticipate that the price I may eventually be allowed to charge will not provide me a sufficient return commensurate with the risks I foresee, I cannot afford to drill. That is an economic fact of life and, believe me, if you were in my position you would have to make the same decision until you foresaw the end to the fallacy of selling gas for less than the cost of replacing it.

There are many varied risks involved in the drilling process. There is always the risk of a dry hole. I am sure that my company will drill many as a result of geological uncertainty -- a component not adequately covered in FPC "Cost" methodology. Also, there is the risk of drilling a marginal producer which, although theoretically economic, absorbs an enormous amount of capital thus keeping it from being redeployed in further exploration. Most wells are marginal. It is obvious that under the current regulatory system, significant capital expenditures will not be made to explore for and develop these fields.

More wells such as the No. 1 Green would bring major quantities of new natural gas at a consumer cost lower than any alternate fuel. This could be done quickly as the pipelines from the traditional supply areas have already been built.

Within the Anadarko Basin area there are already existing and in place ten interstate natural gas pipelines serving some sixty percent of the Nation's gas consumers. These pipelines serve consumers from Los Angeles to Detroit, but because of wellhead price controls they are unable to meet consumer demand.

Total supply deficiencies for these ten pipelines were estimated at 1.5 trillion cubic feet for 1975. By 1980 their supply deficiencies will probably exceed 3.5 trillion cubic feet, an optimistic projection in my opinion as they are counting on Algerian LNG.

I submit that it is economically unsound for Congress to deny producers the opportunity to drill for gas because of an arbitrary price ceiling; for you are, at the same time, denying consumers the right to purchase domestically produced natural gas and in turn forcing them to higher cost foreign sources while deploying American labor to develop foreign oil and gas fields. Additionally, you are presenting the Middle East with the gift of a quickly-widening gas gap. This policy will result in grave national consequences.

The Resource Base for Natural Gas

The resource base for natural gas has caused a great deal of controversy. Estimates of the onshore potential for the lower 48 states range from 65 to 1,777 trillion cubic feet of gas as against our approximate consumption/production rate of 22 trillion cubic feet of gas per year. In my professional judgment, estimates at the lower end of the range are more than merely unrealistic, they are dangerously misleading. The 65 trillion cubic feet estimated by J. D. Moody of Mobil Oil Corporation[5/] for the lower 48 onshore is unrealistically low because that amount is in the middle range (35-150 trillion cubic feet) of remaining natural gas reserves for the Hugoton/Anadarko Province alone.

There are two reasons why such low estimates are made. First, those who have arrived at these conclusions base their analyses on oil statistics and extrapolate to natural gas. But, natural gas is in fact totally different from oil. Such extrapolations as made by Moody and M. King Hubbert[5/] are bound to be inaccurate. All of the largest natural gas fields in the world -- as in the United States -- are not associated with oil in the reservoir. In fact, approximately eighty percent of the gas currently produced is non-associated gas which, by the way, accounts for the importance of the wellhead price of gas (as opposed to oil) in bringing on new supplies.

The second reason why such low reserve estimates are bound to be inaccurate relates to the fact that they are based on statistical analysis of past trends rather than on basin, geological and reservoir analyses. Mid Continent Region producers have drilled more wells than in any other area of the world. Because of the many wells drilled in their area, Mid Continent producers have learned a great deal about the geology and reservoirs.

With this knowledge and by using the basin/reservoir volume of sediments method; we can confidently predict potential reserves more accurately

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[5/] Oil and Gas Journal, September 16, 1974, pp. 25-28, U.S. Oil Policy Riddle: How Much Left to Find?

than the analyst who is simply relying on the statistical method of estimation. The potential remaining reserves lying deep in the Anadarko Basin (Oklahoma and the Texas Panhandle) are in the range of 50 to 100 trillion cubic feet of gas. However, it will necessitate deep and expensive wells to get that gas and, therefore, will not become a reality under any regulatory pricing system.

These reserves are the energy equivalent of from one to three Arctic gas projects. The new deep wells are individually important national resources for:

- -- One well produces enough energy each year to fertilize four million acres of wheat
- -- Three of the best gas wells in Western Oklahoma produce as much energy annually as a 1500-megawatt nuclear power plant
- -- Forty of these wells produce as much energy annually as the entire TVA System.

If Congress would remove the regulatory barriers and uncertainties now by enacting the Senate's bi-partisan compromise bill, as proposed in the House by Krueger (H.R. 10480); sufficient risk capital would be rapidly deployed to develop these resources and that gas would be in the interstate consumer's home as fast as a producing wells could be completed. The lead time is shorter within the onshore traditional supply areas than from any other source of supply for interstate consumers. It will take about five to seven years before Arctic gas will be available for consumers.

Speaking conservatively, we have at least 550 trillion cubic feet of gas remaining to be found onshore. I will not offer my professional opinion in respect to the offshore provinces as my experience in that area is negligible.

So -- what is holding us up? Conspiracies? No -- federal regulation on wellhead prices. And consumers are the ultimate losers. The production from just one successful super-well in the Deep Anadarko Basin is the energy equivalent of one million barrels of oil a year which can do the following:

-- Supply the needs (including industrial) of a typical town of 70,000 people

-- Heat in the winter and cool in the summer the homes of 37,500 people

-- Meet the energy requirements of over 75 hospitals each caring for about 500 in-patients.

In addition to the Deep Anadarko Basin, ultra-deep super-wells may be developed in the Gulf Coast, the Delaware Basin, the Arkoma Basin, the Appalachian Basin, the Mississippi Embayment (including Alabama and Florida), the Rocky Mountain Basins, and in other areas as well.

Competition and Price/Supply Relationships

It is alleged that there is no free market in natural gas; that competition simply does not exist in the natural gas industry and that deregulation will allow OPEC to set the price for natural gas. These allegations are totally erroneous.

First it is important to note that when considering natural gas field price deregulation, only one question is relevant: Are field markets for natural gas effectively competitive? In other words, is the market power of producers balanced by the market power of pipelines in the field?

The answer is "yes". It is not only my answer but the answer of the experts and scholars who have studied the relevant factors for years. For example, the Senate Interior Committee's Majority Report of 1972 (issued as part of the Senate's National Fuels and Energy Policy Study by Senator

Henry M. Jackson) stated:

> "It is not an exaggeration to say that almost all recent studies have found that natural gas field markets would be workably competitive in the absence of Federal price regulation."

My own experience and observations, moreover, make me feel that the competition issue is certainly a red herring when applied to the onshore. Even as the shortage worsens, many factors still determine wellhead prices in a free market. And, despite the shortages, prices have not all jumped (as it was alleged they would) to OPEC price equivalent of $2.00 per Mcf and beyond.

Inevitably, in a competitive market during times of shortage, there has been a rise in price. However, the prices of natural gas are both above and significantly below OPEC cartel levels. The intrastate prices for new natural gas during the first half of 1975 ranged from a low of 20 cents per Mcf to a high of $2.11 per Mcf. The weighted average for the first half of 1975 was $1.75 per Mcf. Therefore, natural gas markets are price responsive -- up and down. A shortage will evoke a higher price plus increased drilling, more supply, less demand and then -- a lower price. That is the way a competitive market performs and that, in fact, has been the reality of the unregulated market.

Allow me to point out that within the State of Oklahoma; we have supply and demand in balance. It was not done at 80 cents per Mcf nor at $1.30 per Mcf, but above and below these prices and, therefore, benefited the consumers whose pipeline suppliers made the judgment themselves (based on many factors) and pay for the incremental needs of consumers.

Oklahoma, with the benefit of competitive pricing, has provided consumers within the State a firm and growing supply, capable of meeting Oklahoma's 4.5 percent per annum increase in demand. In fact, Oklahoma has increased its supply by 25 percent since 1969. Oklahoma's free market system has been tried and proven to accomplish all the stated goals of National energy policy makers:

-- Increase domestic supplies
-- Reduce demand growth rates
-- Eliminate unnecessary reliance on foreign supplies
-- Work against inflationary trends
-- Protect the jobs of the American people

The American people should not tolerate any further delay nor further political confrontations between the Congress and the President on energy policy. The Krueger Bill (H.R. 10480) is the answer to the gas shortage.

A short-term bill is worthless. Agreement on this point is unanimous on the part of key representatives of the Consumer Federation of America, the AFL-CIO, the American Public Gas Association, producers, pipelines, and distributors. The short-term is inseparable from the long-term. Any action designed to meet only the needs of the short-term will aggravate the long-term problems by taking up valuable Congressional time to accomplish nothing.

There should be no gimmicks. Producers and consumers need onshore deregulation of all new gas. There must be no gimmicks in the definition of new gas. There must be no gimmicks which prevent newcomers from market entry. The major oil companies must not be barred from the exploration for and development of new natural gas for they have enormous capital resources (we need all the capital from all the sources that can be found if producers are to close the widening gas gap between now and 1980). The major companies also have many people capable of directing their exploration and development programs for these vitally needed new natural gas reserves. We welcome all competition that can be found the world over.

The Krueger Bill (H.R. 10480) offers the solution to the natural gas shortage. It is a fair compromise and protects consumers both in terms of price and supply. By providing long-term certainty, it will enable producers to raise the funds to undertake extensive drilling programs to provide new gas for the interstate market at reasonable consumer prices.

If the House fails to pass H.R. 10480 timely, the consumer and the Nation will be the losers. Let the competitive system work to encourage maximum development of one of the most abundant potential sources of energy we have in the United States.

I urge you to act on this positive legislation now!

(EXHIBIT A)

THE GHK COMPANY
GREEN WELL PROJECT
DISCOUNTED CASH FLOW CALCULATION OF UNIT COST OF GAS
FPC OPINION NO. 699-H METHODOLOGY 5/4 New Area Rate
MODIFIED BY FPC OPINION NO. 742 RATE OF RETURN 20% v. 15%
CALCULATION DATED 12/04/75.

LINE NO.	(A) YEAR(1)	(B) NET WORKING INTEREST GAS VOLUMES(2)	(C) NET WORKING INTEREST LIQUID VOLUMES(3)	(D) CASH FLOW(4)	(E) INVESTMENT OUTLAY(5)	(F) WORKING CAPITAL COST(6)	(G) G.P. TAX(7)	(H) OPERATING COST(8)	(I) UNDISCOUNTED CASH FLOW(9)	(J) DISCOUNTED NET CASH FLOW(10)
1	61	-	-	-	(200,000)	-	-	-	(200,000)	(200,000)
2	62	-	-	-	(850,000)	-	-	-	(850,000)	(708,333)
3	63	-	-	-	(650,000)	-	-	-	(650,000)	(451,389)
4	64	-	-	-	(300,000)	-	-	-	(300,000)	(173,611)
5	65	-	-	-	-	-	-	-	-	-
6	66	-	-	-	-	-	-	-	-	-
7	67	-	-	-	(300,000)	-	-	-	(300,000)	(100,469)
8	68	-	-	-	(2,800,000)	-	-	-	(2,800,000)	(781,429)
9	69	-	-	-	(1,600,000)	-	-	-	(1,600,000)	(372,109)
10	70	1,972,000	-	6,030,376	(500,000)	(600)	(422,126)	(24,000)	5,083,650	985,245
11	71	1,411,000	-	4,314,838	(2,500,000)	(600)	(302,039)	(24,000)	1,488,199	240,353
12	72	1,045,500	-	3,197,139	(1,000,000)	(600)	(223,800)	(24,000)	1,948,739	262,277
13	73	850,000	-	2,599,300	-	(600)	(181,951)	(24,000)	2,392,749	268,363
14	74	875,500	-	2,677,279	-	(600)	(187,410)	(24,000)	2,465,269	230,414
15	75	807,500	-	2,469,335	-	(600)	(172,853)	(24,000)	2,271,882	176,949
16	76	782,000	-	2,391,356	-	(850)	(167,395)	(34,000)	2,189,111	142,085
17	77	765,000	-	2,339,370	-	(600)	(163,756)	(24,000)	2,151,014	116,344
18	78	722,500	-	2,209,405	-	(8,100)	(154,658)	(324,000)	1,722,647	77,645
19	79	680,000	-	2,079,440	-	(600)	(145,561)	(24,000)	1,909,279	71,715
20	80	637,500	-	1,949,475	-	(600)	(136,463)	(24,000)	1,788,412	55,979
21	81	595,000	-	1,819,510	-	(600)	(127,366)	(24,000)	1,667,544	43,496
22	82	552,500	-	1,689,545	-	(600)	(118,268)	(24,000)	1,546,677	33,620
23	83	510,000	-	1,559,580	-	(600)	(109,171)	(24,000)	1,425,809	25,827
24	84	467,500	-	1,429,615	-	(600)	(100,073)	(24,000)	1,304,942	19,698
25	85	425,000	-	1,299,650	-	(600)	(90,975)	(24,000)	1,184,074	14,895
26	86	382,500	-	1,169,685	-	(600)	(81,878)	(24,000)	1,063,207	11,145
27	87	340,000	-	1,039,720	-	(600)	(72,780)	(24,000)	942,340	8,232
28	88	170,000	-	519,860	-	(600)	(36,390)	(24,000)	458,870	3,340
TOTAL	-	13,991,000	-	42,784,478	(10,700,000)	(19,150)	(2,994,913)	(766,000)	28,304,415	281

TOTAL
RATE 3.0580

(APPENDIX B)

THE GHK COMPANY

GREEN WELL PROJECT
CALCULATION OF COST OF SERVICE
EXCLUDING RETURN COMPONENT

		Amounts
	Depletion Period	
1.	Years	19
	Volumes (N.W.I.)	
2.	Gas (Mcf)	13,991,000
3.	Liquids (Bbls)	-0-
	Rate Base	
4.	G & G	$ 1,000,000
5.	Leasehold	1,000,000
6.	Drilling & Completion	8,700,000
7.	Salvage Value	-0-
8.	Total Investment	$10,700,000
	Cost of Production	
9.	Return	$ -0-
10.	Operating Expenses[1]	756,000
11.	D. D. & A	10,700,000
12.	Regulatory Expense	10,000
13.	Liquid Credit	-0-
14.	Total Cost	$11,466,000
	Unit Cost of Gas	
15.	Direct Cost of Production[2]	$ .8195
16.	Indirect Costs	-0-
17.	Subtotal	.8195
18.	G.P. Tax [3]	.0573
19.	Unit Cost	.8768

[1] $24,000 yearly, plus $300,000 workover.
[2] Line 14 divided by Line 2.
[3] 7% of Line 17.

TESTIMONY

of the

NATIONAL RETIRED TEACHERS ASSOCIATION

and the

AMERICAN ASSOCIATION OF RETIRED PERSONS

on

COMPREHENSIVE NATIONAL ENERGY POLICY: THE NATURAL GAS COMPONENT

before the

SUBCOMMITTEE ON ENERGY AND POWER

of the

COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE

U.S. HOUSE OF REPRESENTATIVES

January 28, 1976

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MR. CHAIRMAN:

I am James M. Hacking, a Legislative Representative of the National Retired Teachers Association and the American Association of Retired Persons. These affiliated organizations have a combined membership of approximately 9 million older persons.

With me this afternoon are Mr. Peter W. Hughes, our Assistant Legislative Counsel, and Mr. Thomas C. Borzilleri, our Staff Economist.

I. ENERGY POLICY DEVELOPMENT: FAR FROM COMPLETE

While the Energy Policy and Conservation Act was a significant legislative step in the development of a comprehensive energy policy, a complete and perfected policy is still lacking. The next area with respect to which the Congress must make decisions is natural gas.

We realize that remaining domestic resources of natural gas are finite and dwindling. We also realize that we must encourage, through reasonable incentives, development and production of those remaining resources to supply our energy needs over the near term while we advance, encourage or create the research, technology, and incentives necessary to bring new sources such as solar energy, shale oil and nuclear power, into the supply stream. But we are not willing to pay more than is reasonably necessary to achieve this end. If we must pay more, we ask that we be given our money's worth.

While such factors as environmental impact, foreign policy, the rate of growth in GNP and the rates of inflation and unemployment have been part of the general debate on comprehensive national energy policy, the very serious impact of rising prices on lower and fixed-income persons has received only modest attention from the Congress, and little, if any, from the Administration and the oil-natural gas industry.

Certainly, our Associations have no doubt that the sudden and exorbitant increases in domestic and foreign energy prices that followed the Arab oil embargo resulted in an enormous transfer of purchasing power from domestic consumers to domestic and foreign energy producers and contributed substantially to the 1974 inflation rate that left the domestic consumer with significantly reduced real disposable income.[1] We therefore agree with the general consensus that, in order to reduce our reliance on foreign imported oil and our vulnerability to international commodity disruptions, a comprehensive energy policy must be formulated that will, with the least inflation and unemployment consequences, reduce demand for energy, promote conservation and stabilization of energy prices, and still provide the incentives necessary to encourage the efficient development of the remaining energy potential of this country.

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[1] See Table I in Appendix, p. 15.

These are the macro effects which a comprehensive national policy should be designed to achieve. But any policy that has potential to achieve these ends should also take into account the micro effects -- one of which is the potential impact of a particular policy on those who have limited ability to pay still higher energy prices. Certainly, this group includes a substantial percentage of the aged.

II. NATURAL GAS: A PUBLIC UTILITY TO BE REGULATED ACCORDINGLY

Our Associations' 20-member Legislative Council, having recently concluded its annual policy review, has again endorsed the natural gas position espoused by our organizations for the past two years.

As in the case of public utility monopolies, we believe that the natural gas industry should continue to be subject to price ceiling regulation with respect to the wellhead price of both "old" and "new" interstate natural gas and such regulation should be extended to the intrastate gas market.

We see before us an industry which includes many individual producers at the wellhead but which is dominated by a relatively small number of enormously powerful, giant corporations. We see before us a nationwide and complex network of pipelines. We see the various industries served by those lines and the public utility distribution companies which, in turn, serve residential and small commercial consumers. Forty million residences lie at the end of this vast network -- residences in need of regulatory protection.

Our Associations' position should not be construed as approving the efficiency, quality or effectiveness of present FPC regulation. We are not happy with the status quo and we know of no one who really is. However, when confronted with a market structure such as that which we are pursuaded exists in natural gas, we cannot help but demand that the federal government provide through a reformed, efficient and comprehensive regulatory structure, protection against the abusive use of the enormous market power possessed by the relatively small number of major producers which dominate this entire market -- all the way from the wellhead to the burner tip.

Our Associations' members, many of whom are poor and most of whom live on relatively fixed incomes, are as willing as other population groups to pay more to increase our domestic energy supplies and reduce our dependence on foreign imported and artificially priced energy products. We think everyone would agree that we must, as a people, pay whatever it costs to produce and deliver to market as much of our remaining potential resources as possible. We ask only that the price charged to us as consumers to bring forth these supplies reflect no more than what it costs to produce them and still provide a rate of return on investment reasonably sufficient to attract the capital needed to achieve that end. We are not willing to pay prices that are pegged to artificial, and perhaps ever-escalating, price levels set by the Organization of Petroleum Exporting Countries (OPEC).

III. THE IMPACT OF HIGHER ENERGY PRICES ON THE AGED: SOMETHING THAT SHOULD BE TAKEN INTO ACCOUNT IN THE DEVELOPMENT OF COMPREHENSIVE NATIONAL ENERGY POLICY

Direct energy consumption of natural gas, fuel oil, electricity and gasoline, is essential to the conduct of every-day activities such as home heating, cooking, appliance operation, lighting and transportation. However, the volume and intensity of these activities per family unit are closely related to factors such as income, age, household size, prices, climate, health status, and environmental conditions.

Certainly, age and income are important factors to be taken into account in assessing the potential impact of projected price levels under alternative energy policies. The final report[2/] prepared by Applied Management Sciences (AMS report) for the Consumer Affairs/Special Impact Office of the Federal Energy Administration, found that the dollar amount spent on direct energy use varies directly with family income. With respect to elderly family units, that report found that

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[2/] See Applied Management Sciences, "A Study of the Effects of Rising Energy Prices on the Low and Moderate Income Elderly," prepared for the Consumer Affairs/Special Impact Office of the Federal Energy Administration (March 1975) (hereinafter referred to as AMS Report).

upper-middle income aged units spend dramatically more on direct energy uses than lower middle-income units. Moreover, that report found that the aged poor consume less energy than any other age-income group, including the non-aged poor, and yet spend a much higher proportion of their budget on energy expenditures.

The General Accounting Office, in its recent report to the House Government Operations Committee on the implications of deregulating the price of natural gas, endorsed similar conclusions and stated:

> '...poor families spend about 15 percent of their incomes on energy, while higher income groups spend from 7 to 4 percent of their income on energy. Because of these relationships, any increase in natural gas prices would be felt by poor families who are forced to spend an even larger portion of their incomes on energy.3/

While our Associations are not suggesting that all the elderly are poor, or that all of them would suffer undue economic hardship under the price levels which would prevail if deregulation were elected as the best natural gas policy, we would point out that 45.3 percent of them had total money income of under $4,000 in 1973 and 15.7 percent of them were below the defined level of poverty.4/

3/See Table II in Appendix, p. 16.

4/See Tables III and IV in Appendix, pp 17, 18.

Another important finding contained in the AMS report was the substantial variation in consumption rates of particular energy sources by aged family units at different income levels. Less variation among aged units in natural gas consumption relative to other energy sources indicates the degree to which natural gas must be classified as a necessity (because it is used for such essential functions as home heating, cooking and water heating). Consumption of this energy source is relatively inelastic and can be reduced only marginally no matter how high the price.

The AMS findings that home heating makes up a large portion of household consumption of direct energy sources and that this activity is effected by the size and structure of the household unit and its insulating characteristics, which, in turn, are related to the socio-economic conditions of the elderly household, were not surprising to us. Significant numbers of the aged-occupied units are inadequate; moreover, annual expenditures by aged households for home improvements and home maintenance tend to be less than those of the general population. Also, home heating and home fuel consumption are obviously affected by such factors as climate, the types of fuel relied upon for home heating purposes in various parts of the country, and the differential in prices for these various types of energy.

In terms of public policy, these findings suggest to us that the government must be sensitive to what would be the impact of still higher energy prices for the poor, near-poor and fixed-income. It is not enough for the Administration, the oil-natural gas industry and many economists to tell us that an energy market free of federal involvement will eventually sort things out and that higher prices will, in time, elicit more supplies and restrain demand.

We believe that if a decontrol policy were followed with respect to natural gas, all domestic natural gas prices would tend to be pegged on the BTU equivalent basis to the artificial prices established from time to time by the OPEC cartel. It is ironic that while denouncing the artificial pricing practices of OPEC, decontrol advocates seem anxious to pursue a policy that would permit domestic producers to charge those same prices -- prices that are unjustified on the basis of cost of production, and reasonable rates of return on investment.

Although the pricing system could be a useful device to allocate some scarce energy resources to middle and upper-income citizens who have been using them wastefully, higher prices would bear harshly on the poor and fixed-income who, as should be evident, use energy for necessities, have little or no opportunity to cut back on their use, and do not have the ability to pay still higher prices without suffering real hardship. National energy policy cannot ignore the human condition and should attempt to mitigate the impersonal hardships of the market mechanism and adjust constructively those problems which the market leaves untouched.

While we suspect that the Congress is likely to provide some means to mitigate these impersonal hardships on the poor and fixed income, we hope that the Congress does not make the mistake of deregulating energy prices. We fear that if such a policy is pursued, the only means that will be readily available in terms of public policy to mitigate the economic hardships that will result from unjustifiably high price levels, will be the establishment and expansion of yet another welfare program. We wonder whether those who are vigorous in their support of deregulation will be as equally vigorous in the support of a stamp program with respect to fuel such as exists with respect to food.

IV. THEORY OF THE CURRENT SHORTAGE

The proponents of deregulation contend that the current natural gas shortage which is becoming acute in the interstate market is regulator-induced. Had the 20-year FPC experiment in wellhead price regulation not restrained natural gas prices at artificially low levels, simultaneously stimulating demand while discouraging exploration, development and extraction, the current shortage would not exist. FPC regulation is alleged to have kept natural gas prices below the market equilibrium level that would have otherwise obtained. Proponents argue that under a competitive market structure, in the absence of regulatory interference, prices would have risen to the level required to elicit the increments needed to satisfy current and future demand. Moreover, as prices rose, demand would have fallen. For them, the simple solution is to deregulate natural gas prices in order to allow the market price mechanism to equate supply with demand, thereby eliminating the shortage.

Our Associations have no doubt that the ordinary operation of the pricing mechanism in essentially competitive markets is an excellent means for equating supply and demand for any product. In an atmosphere of acute rivalry among numerous and truly independent sellers, producers recover their production costs and the going rate of return on their investment; consumers obtain the supply demanded at the lowest possible price. If the quantity demanded exceeds the quantity supplied, prices and profits will rise, additional investment will be attracted, and supply will increase. The result -- equilibrium between supply and demand. Moreover, during a period of excess demand, the pricing system will ration the product.

Whether deregulation of natural gas prices is an appropriate policy response to the current shortage must depend upon whether the natural gas industry is sufficiently competitive such that, along with deregulation and higher prices, supply increments will be forthcoming that will justify those price levels and eventually moderate the initial price surge.

If, having examined the evidence, it is concluded that the natural gas industry is not workably competitive, then price deregulation will mean that the inefficiency of current regulation of the interstate natural gas market by the Federal Power Commission will be succeeded by the inefficiency of oligopoly pricing. In the absence of workable competition, the result of deregulation will be unjustifiably higher prices.

V. THE INDUSTRY STRUCTURE

Our Associations have examined the evidence available with respect to the natural gas industry structure. While that evidence is far from conclusive and should be expanded and considered carefully by this Subcommittee, we are pursuaded that the industry is not adequately or workably competitive. The industry appears oligopolistic in character with overwhelming imperfections in both buying and selling. We expect that deregulation will result in billions of dollars of unjustifiable, additional cost to consumers -- with no guarantee of a reasonable supply response.

In view of the substantial price increases that are the certain consequences of deregulation, our Associations believe that the burden of proving, beyond any reasonable doubt, that the industry is workably competitive is on the proponents of that policy. In our opinion, the proponents have thus far failed to prove their case.

Since we would like to amplify our comments with respect to the structure of the industry which we see today, I would like to submit for the record of this hearing, an addendum to our testimony.

VI. NATURAL GAS POLICY RECOMMENDATIONS

We believe that natural gas policy legislation should include the following components:

First, we believe that a single national rate (subject to adjustment for inflation) for "new" gas should be established and "old" gas prices should be frozen. Second, "new" gas prices should be based on prospective (rather than historic) costs and fair rates of return. Third, the least efficient uses of gas should be prohibited. Fourth, improved and streamlined regulatory procedures should be adopted. Fifth, production should be required by lease-holders in the federal domain. Sixth, reformed FPC regulation should be extended to the intrastate gas market. Seventh, joint bidding and joint ventures by major producers, banking interlocks and other anti-competitive practices should be ended.

Finally, an independent, public corporation should be created to produce competitive pressures in the off-shore areas and provide a much-needed yardstick with which to measure profits, costs, and production techniques.

The only legislation that we believe to be reasonably in accord with the recommendations we have made is the National Gas Production and Conservation Act of 1975 (S. 692). We recommend it to this Subcommittee.

Mr. Chairman, this concludes our statement.

APPENDIX

TABLE I

ANNUAL RATES OF CHANGE FOR SELECTED MEASURES OF INCOME AND EARNINGS*

	1965-69	1970	1971	1972	1973	1974	1973:IV	1974:I	1974:II	1974:III	1974:IV
Real Disposable Income	4.0	3.1	4.5	6.9	3.8	-3.0**	0.7	-7.9	-4.4	-0.4	N.A.
Real Per Capita Disposable Income	2.8	2.0	3.5	6.0	3.1	-3.7**	0	-8.5	-5.0	-1.1	N.A.
Real Adjusted Hourly Earnings, Private Non-farm	2.9	0	3.2	3.1	-1.1	-3.4	-2.7	-6.6	-1.4	-2.8	-2.8
Real Adjusted Weekly Earnings, Private Non-farm	0.7	-1.6	3.7	3.7	-2.0	-4.6	-4.0	-8.1	-2.7	-1.1	-6.3
Real Spendable Weekly Earnings***	-0.4	-1.2	4.4	4.4	-3.4	-5.3	-4.6	-8.4	-3.6	-2.2	-6.9
Real Compensation Per Manpower, Total Private	2.9	1.1	2.8	3.5	-2.0	-2.0	-1.3	-4.5	-1.6	-2.5	-2.8

*Percent changes for annual data are based on 4 quarter changes, from 4th quarter to 4th quarter; percent changes for quarterly data are based on quarterly averages expressed at compound annual rates.

**Percent changes from 3rd quarter, 1973 to 3rd quarter, 1974, the most recent quarter for which data were available at press time.

***Earnings expressed in 1967 dollars for a worker with 3 dependents.

Source: Bureau of Labor Statistics, Department of Labor, and Bureau of Economic Analysis, Department of Commerce

TABLE II

PERCENTAGE OF FAMILY INCOME SPENT ON ENERGY AND NATURAL GAS (1972-73)

Average Family Income ($)		Average Annual BTU's (Millions per Household)	Average Annual Cost per Household	Percent of Total Annual Income Spent on Energy
$ 2,500	Total Energy	207	$379	15.2
	Natural Gas	118	147	5.9
$ 8,000	Total Energy	294	$572	7.2
	Natural Gas	129	153	1.9
$14,000	Total Energy	403	$832	5.9
	Natural Gas	142	166	1.2
$24,500	Total Energy	478	$994	4.1
	Natural Gas	174	200	.8

Source: "A Time to Choose: America's Energy Future," Energy Policy Project of the Ford Foundation (Cambridge, Mass., Ballinger Publishing Co., 1974)

TABLE III

1973 ANNUAL INCOME BY AGE*

PERCENT OF POPULATION** BY INCOME LEVELS

Current Total	Age 65 and Over			Age 25-64		
Money Income	All Consumer Units	Families	Nonfamily Persons	All Consumer Units	Families	Nonfamily Persons
Under $1,000	2.8%	0.8%	5.3%	1.9%	1.0%	6.2%
$ 1,000 to $ 1,499	4.9	1.1	9.7	1.1	0.5	4.2
$ 1,500 to $ 1,999	6.9	2.0	13.0	1.5	0.8	5.0
$ 2,000 to $ 2,499	8.9	3.1	16.1	1.7	0.9	4.9
$ 2,500 to $ 2,999	8.6	4.9	13.2	1.5	1.1	3.4
$ 3,000 to $ 3,499	7.1	5.5	9.0	1.7	1.3	4.0
$ 3,500 to $ 3,999	6.1	5.8	6.5	1.6	1.3	3.5
$ 4,000 to $ 4,999	10.8	12.4	8.9	3.9	2.9	8.5
$ 5,000 to $ 5,999	8.3	10.6	5.3	4.0	3.2	7.7
$ 6,000 to $ 6,999	6.3	8.8	3.2	4.2	3.6	6.7
$ 7,000 to $ 7,999	4.4	6.5	1.8	4.7	4.3	6.9
$ 8,000 to $ 8,999	4.0	5.7	1.8	5.1	4.7	6.8
$ 9,000 to $ 9,999	3.0	4.2	1.4	4.9	4.8	5.5
$10,000 to $11,999	4.5	6.7	1.8	10.9	11.4	8.8
$12,000 to $14,999	4.8	7.6	1.2	15.1	16.4	8.8
$15,000 to $24,999	6.0	9.9	1.3	26.8	30.8	7.4
$25,000 to $49,999	2.0	3.4	0.4	8.4	9.9	1.2
$50,000 and Over	0.6	1.0	0.1	1.0	1.1	0.5
Midpoint (Median)	$4,441	$6,426	$2,725	$12,243	$13,500	$7,367
Arithmetic Average (Mean)	6,696	9,023	3,772	13,681	14,965	7,533
% Under $4,000	45.7%	23.0%	62.2%	11.0%	6.9%	31.2%
% Over $12,000	13.[illegible]	21.9%	3.0%	51.3%	59.2%	17.9%

*Tabulation developed from Table 25, Consumer Income Current Population Reports, P-60, No. 97.

**Age population based on March, 1974 Current Population Reports Estimate.

TABLE IV

PERSONS BELOW THE LOW-INCOME LEVEL 1959 TO 1974

	1974	1973	1972	1971	1970	1969	1968	1967	1966	1965	1964	1960	1959
TOTAL (all persons)	11.6	11.1	11.9	12.5	12.6	12.1	12.8	14.2	14.7	17.3	19.0	22.2	22.4
65 years & over	15.7	16.3	18.6	21.6	24.6	(NA)	25.0	29.5	28.5	(NA)	(NA)	(NA)	(NA)

Source: Bureau of Census (Dept. of Commerce), Current Population Reports: Consumer Income, Series P-60, No. 99, 18 (Table 15), (July 1975).

TABLE 4-1: ENERGY CONSUMPTION BY POOR AND NON POOR HOUSEHOLDS AND BY THE ELDERLY

	Base (No. in sample)	(1) Average BTU's Per Household*		(2) Price Per Unit		(3) Average Cost Per Household	(1a) BTU Index	(2a) Per Unit Price Index	(3a) Cost Index
Natural Gas									
All households	1,455	141.8	x	$1.18	=	$166.8	100	100	100
All poor households	279	118.4	x	1.24	=	146.8	84	105	88
All non-poor households	1,106	144.4	x	1.17	=	169.2	102	99	101
Poor households with head 65 or over	115	118.8	x	1.20	=	142.4	84	102	85
Non-poor households with head 65 or over	168	129.3	x	1.21	=	156.6	91	103	94
Electricity									
All households	1,455	93.1	x	2.09	=	194.3	100	100	100
All poor households	279	55.2	x	2.38	=	131.4	59	114	63
All non-poor households	1,106	99.0	x	2.06	=	203.7	106	99	105
Poor households with head 65 or over	115	47.4	x	2.44	=	115.9	51	117	60
Non-poor households with head 65 or over	168	71.8	x	2.24	=	161.0	77	107	83
Gasoline									
All households	1,455	127.0					100		
All poor households	279	63.4					50		
All non poor households	1,106	135.6					107		
Poor households with head 65 or over	115	50.6					40		
Non-poor households with head 65 or over	168	95.4					75		

*BTUs are expressed in millions.

Source: Washington Center for Metropoli[illegible]s' Lifestyles and Energy Surveys

TABLE 4-2: AMOUNT, PRICE AND COST OF ENERGY BY ENERGY SOURCE AND INCOME, 1972-73

Energy Source	Average annual BTU (millions) per household	Average price per million BTU	Average annual cost per per household	Percent of average income(a) spent on energy
All 3 energy sources				
Poor	207	$1.83	$379	15.2%
Lower middle	294	1.95	572	7.2
Upper middle	403	2.06	832	5.9
Well-off	478	2.08	994	4.1
Natural gas				
Poor	118	1.25	147	5.9
Lower middle	129	1.19	153	1.9
Upper middle	142	1.17	166	1.2
Well-off	174	1.15	200	.8
Electricity				
Poor	55	2.38	131	5.2
Lower middle	80	2.07	167	2.1
Upper middle	108	1.97	213	1.5
Well-off	124	2.11	262	1.1
Gasoline				
Poor	34	2.96	101	4.0
Lower middle	85	2.96	252	3.2
Upper middle	153	2.96	453	3.2
Well-off	180	2.96	532	2.2

(a) The average income of the poor, lower middle, upper middle and well-off are $2,500, $8,000, $14,000 and $24,500 respectively. The averages for the upper middle and well-off were adjusted using unpublished data from the U.S. Census Bureau. The poverty thresholds are as follows: under $3,000 for 1 or 2 people; under $5,000 for 3-4 people; under $7,000 for 5-6 people; and under $9,000 for families of 7 or more.

Source: Reprinted from Washington Center for Metropolitan Studies, Energy in People's Lives, August 22, 1974 (manuscript).

PERCENTAGE OF "ELDERLY" HOUSEHOLDS INADEQUATELY HOUSED, OWNER OCCUPIED HOUSING, 1970

Household Income	Number of persons in the household					Percent by Income Class
	1	2	3 & 4	5	6	
less than 2,000	.2412	.1101	.0198	.0026	.0038	.3775
2,000 - 2,999	.0463	.0822	.0165	.0018	.0035	.1505
3,000 - 4,999	.0298	.1001	.0295	.0040	.0081	.1715
5,000 - 7,499	.0115	.0606	.0310	.0047	.0013	.1091
7,500 - 9,999	.0039	.0307	.0231	.0043	.0115	.0735
10,000 - 14,999	.0022	.0190	.0260	.0053	.0174	.0699
15,000 19,999	.0005	.0035	.0085	.0022	.0087	.0234
20,000 plus	.0004	.0023	.0042	.0014	.0069	.0152
Percent by Family Size	.3358	.4085	.1586	.0263	.0543	1.000

Source: Derived from Unpublished Tabulation done by Bureau of Census for H.U.D., 1972.

PERCENTAGE OF "ELDERLY" HOUSEHOLDS INADEQUATELY HOUSED, RENTER OCCUPIED HOUSING, 1970

Household Income	Number of persons in the household					Percent by Income Class
	1	2	3 & 4	5	6	
less than 2,000	.3949	.0813	.0154	.0024	.0034	.4998
2,000 - 2,999	.1168	.0644	.0117	.0017	.0028	.1991
3,000 - 4,999	.0748	.0732	.0174	.0030	.0061	.1775
5,000 - 7,499	.0257	.0330	.0112	.0024	.0064	.0787
7,500 - 9,990	.0059	.0096	.0049	.0012	.0044	.0260
10,000 - 14,999	.0029	.0052	.0037	.0010	.0047	.0175
15,000 - 19,999	.0006	.0011	.0011	.0004	.0018	.0050
20,000 plus	.0004	.0007	.0008	.0003	.0015	.0037
Percent by Family Size	.6220	.2685	.0662	.0124	.0311	1.000

Source: Derived from Unpublished Tabulation done by Bureau of Census for H.U.D, 1972.

OWNER AND RENTER OCCUPIED HOUSING UNITS BY LIVING CONDITIONS, ELDERLY HOUSEHOLDS 1970

Household Size	Owners	Renters
	INADEQUATE	
1 person	733,095	2,002,625
2	891,722	864,220
3 or 4	346,114	212,919
5	56,719	39,856
6 or more	155,113	99,849
	2,182,793	3,219,469

2,182,793 + 3,219,469 = 5,402,262

Household Size	Owners	Renters
	ADEQUATE	
1 person	2,362,588	653,441
2	5,073,523	1,037,234
3 or 4	1,946,544	421,485
5	366,933	72,164
6 or more	350,928	56,094
	10,100,516	2,240,418

10,100,516 + 2,240,418 = 12,340,921

Source: Derived from Unpublished Tabulation done by Bureau of Census for H.U.D., 1972.

TESTIMONY OF EDWIN ROTHSCHILD
ACTING EXECUTIVE VICE PRESIDENT
AMERICAN PUBLIC GAS ASSOCIATION
BEFORE THE SUBCOMMITTEE ON ENERGY AND POWER
OF THE INTERSTATE AND FOREIGN COMMERCE COMMITTEE
OF THE UNITED STATES HOUSE OF REPRESENTATIVES

January 28, 1976

Mr. Chairman, my name is Edwin Rothschild and I am the acting Executive Vice President of the American Public Gas Association. The Association is composed of over 200 municiapply-owned gas distribution systems located in more than 30 states. Owned and operated by the citizens of the community, these systems are directly responsive to the needs of consumers. I want to thank this Subcommittee for the opportunity to appear on behalf of the American Public Gas Association and to testify on some of the fundamental issues regarding the regulation of natural gas.

Also testifying on behalf of our Association is our General Counsel, Mr. Charles F. Wheatley, Jr. Mr. Wheatley in his testimony will deal specifically with the legislation being considered by this subcommittee, while I shall direct my testimony to a general overview of the problems facing the natural gas industry and why it is imperative that regulation of natural gas sales at the wellhead not only be continued, but be expanded to cover the unregulated intrastate markets as well.

Leaving aside for the moment a discussion of monopoly power in the natural gas producer market and leaving aside the fact that producers have underreported reserves and delayed production in anticipation of higher prices and leaving aside the fact that the Federal Power Commission has not only advocated deregulation, but failed to adequately protect consumers by enforcing its own rules and regulations, the first issue which must be faced in Congress is what impact deregulation will have on the nation's economy.

In the first place there is no producer that will testify that deregulation will result in reserve additions of 20 to 25 trillion cubic feet a year which are necessary to insure increased production. This is because the producers will not guarantee that higher prices for natural gas will be used solely for natural gas exploration, development and production. In this context, it is important to understand that in 1971 all but two major producers signed a settlement agreement in the Southern Louisiana Area Rate Case which stated:

> it is believed that the ceiling prices and other provisions contained herein will make funds available to the producing industry and create a regulatory atmosphere which should provide an incentive for a substantial increase in exploratory and developmental activities and make a major contribution to bringing forth additional supplies of gas from the Southern Louisiana Area to meet the demands of all consumers supplied by this area.

Nevertheless, despite this agreement, since 1971 producer sales to the interstate market have declined and interstate pipelines have been curtailing many of their large industrial and commercial customers. Although there has been additional drilling, much of it successful, producers are not proving up reserves; they are diverting gas from the interstate market and are delaying production. Thus, instead of providing economic incentives, deregulation will merely reward producers for their efforts to withhold gas from the interstate market.

More importantly, deregulation will have an adverse impact on consumers. Our members, for example, will be most directly affected. There will be a transfer from consumers to producers, if new gas is deregulated, ranging between $12 and $22 billion a year according to a recent Library of Congress study. These price increases will be felt directly by the residential user in higher fuel bills and indirectly by all consumers. This is so because all industrial and commerical users of natural gas will also pass on their higher fuel costs. Thus, food, clothing, rents and other vital goods and services will also increase in price as a result of deregulation. The Library of Congress study also predicts that deregulation will increase unemployemnt and inflation as a direct result of this massive "energy shock," a shock similar to the sudden increase in oil prices in 1973-74. As you know consumers around the country are angry. They are organizing compaigns against higher fuel and utility bills. If Congress passes deregulation, these bills will increase even more giving rise to further economic injury to consumers. In 1938 Congress in its wisdom saw the need to regulate this monopolistic industry to protect consumers and in 1954 the Supreme Court reaffirmed Congress's intent in regulating the entire industry--producers and pipelines.

The producers, however, earning monopoly profits on their oil production are still not satisfied. The producers, earning monopoly profits on their production of coal, are still not satisfied. The producers, earning monopoly profits on their production of uranium, are still not satisfied. They want more. This is why they are pressing Congress for deregulation.

Thus, there has been a great deal of misinformation generated in the public media by members of the administration and natural gas companies about the need to deregulate the price of natural gas. This misinformation is premised on the following false assumptions: (1) that the natural gas producer market is competitive; (2) that regulation has caused the shortage; (3) that the regulated price is not a "just and reasonable" price; (4) that deregulation will result in prices that are competitively determined and fair; and (5) that supply is responsive to price.

The major assumption is, of course, that the natural gas producer market is competitive--namely, that prices are determined by the free interplay of independent producers effectively competing with each other to sell gas to competing buyers. There is ample evidence, however, to prove that the natural gas producing industry is not competitive now, was not competitive when Congress passed the Natural Gas Act in 1938, was not competitive in 1950 when President Truman vetoed deregulation legislation; was not competive when the Supreme Court ruled in 1954 that the Federal Power Commission had to regulate producers and in 1975 and 1976 when the federal courts have reaffirmed that deregulation (administratively by the FPC) would result in a marketplace regulated by a non-competive industry.

In addition to the question of competition in the natural gas producer market, there is a corollary problem which clearly demonstrates the market power of the major oil companies. This problem is being examined by this and Rep. Moss' Subcommittee. It is the problem of producer withholding of natural gas supplies and the underreporting of natural gas reserves. One of the major arguments the producers make is that FPC regulation has caused the shortage of gas in the interstate market. There is, however, sufficient evidence to conclude that there have been a series of efforts by producers to delay development and production, to divert interstate supplies to intrastate markets, to shut-in producible reserves and to underreport reserve findings. To these efforts must be added the unwillingness of interstate pipelines to insure delivery of gas from the producers and to take the producers to court to enforce delivery under contract provisions.

Finally, the producers and deregulation advocates claim that the Federal Power Commission has kept the price of natural gas too low in comparison to the price of gas in the unregulated intrastate market and in comparison to the price of other fuels. This argument is clearly erroneous. In the first place, since 1969 when the Nassikas Commission began to operate, the FPC has continually raised the price of gas, provided producers with even greater expectations of price increases, advocated and attempted administratively the deregulation of natural gas prices, failed to enforce the delivery requirements in producer contracts with pipelines; failed to collect (until recently) reserve information from the producers and relied solely on unaudited industry data which has been shown to be biased and subject to manipulation. In short, for the past six years the Federal Power Commission has provided producers with enormous incentives, but the result has been a decrease, not an increase in supplies for the interstate market. In fact because of the FPC's refusal to alleviate the discrimination against interstate commerce by intrastate markets, the American Public Gas Association and the Consumer Federation of American have gone to court to ask that the Court direct the FPC to regulate the intrastate market which the FPC has allowed to divert gas away from the interstate market.

The existence of unregulated intrastate markets side by side with the regulated interstate market has resulted in serious discrimination against interstate consumers, as well as exploitation of intrastate consumers. It is important to understand how intrastate prices are determined. Until 1972-73, intrastate prices were comparable to interstate prices. In fact, after the Federal Power Commission increased the price of new gas in the Permian Basin in 1973 to 35 cents per Mcf, all intrastste contracts were immediately raised to that level. The point is that prices in the intrastate market are not determined by competitive forces, and thus the price of $1.50 to $2.00 an Mcf is approximately three to four times the cost of that gas. The market price, if it were competitively determined would be cost plus a fair rate of return. And that is why Congress in its wisdom saw fit to regulate this monopolistic industry. Regulation is a substitute for the free, competitive marketplace, which does not exist in the natural gas producer market. As to other fuels, such as oil and coal, it can be convincingly argued that their prices are set artificially high by monopolistic forces--the combination of the OPEC cartel and the shared monopoly of major international oil companies.

Given this brief introduction, I would like to go into some more detail on the issues and questions I have raised.

The present effort by the major producers of natural gas, that is the major oil companies, to get Congress to deregulate is not new. In the late 1940's, following the release by the Federal Power Commission if its three year investigation of the natural gas industry and following a decision by the Supreme Court in the landmark case, Interstate Natural Gas Co. v. FPC, the producers realized that unless specific legislation was passed by Congress exempting them from regulation, the FPC would soon begin to regulate the price of natural gas sold at the wellhead.

The first bill to exempt producers from regulation was introduced in 1947 in response to the Supreme Court's decision which held that the FPC had jurisdiction over certain producer sales of natural gas which were destined for the interstate market. As the Court stated:

> Unreasonable charges exacted at this stage of the interstate movement becomes perpetuated in large part in fixed items of costs which must be covered by rates charged subsequent purchasers of the gas, including the ultimate consumers. It was to avoid such situations that the Natural Gas Act was passed.

The so-called Moore-Rizley bill only passed in the House. The producers and their allies in the Congress tried again in 1949 with the introduction of the Kerr-Thomas bill. Recognizing that the Federal Power Commission's majority was now in favor of regulating producers, the bill's sponsors made every effort to pass this legislation, including labeling the then Chairman, Leland Olds, as a Communist. Such an attack on Olds although malicious, was comprehensible in light of the fact that Olds had become a strong supporter of producer regulation following the results of the FPC's investigation of the natural gas industry, which indicated that the major oil companies controlled most of the natural gas production and reserves.

Thus, taking note of a 1950 debate in both the House and the Senate, the issues are strikingly similar to the issues being considered by this subcommittee. Indeed, on March 31, 1950 Rep. Ray Madden in opposing the Kerr-Thomas bill observed,

> If enacted into law, it will create an unregulated monopoly on the production and price of natural gas to the consuming public throughout the country.

And Rep. Crosser of Ohio argued that,

> ...the most important principle of political economy is involved in this bill. The question is whether or not we shall permit a small handful of persons, a very small group indeed, to grab, to seize the resources of the earth, for its selfish interests, its special benefit, and in utter disregard of the welfare and rights of the great mass of citizens, of substantially all the people of this country.

The Kerr-Thomas bill passed the Senate by a comfortable margin and was narrowly passed in the House by a vote of 176 to 174. But, President Truman recognizing that "the concentration of ownership of natural gas reserves" by a few major companies limited competition vetoed the bill on April 15, 1950. He noted that the continuance of the FPC's authority to regulate sales of gas to interstate pipelines "will adequately protect the public interest by permitting the Commission to prevent unreasonable and excessive prices, which would give large windfall profits to gas producers, at the expense of consumers, with no benefit to the Nation in terms of additional exploration, and production."

The next challenge to the FPC's authority to regulate the producers of natural gas came following the Supreme Court's famous Phillips decision in 1954. Despite Truman's veto in 1950, the producers were still not being regulated, because there was now a majority on the Commission, who were appointed by President Eisenhower, who did not believe in producer regulation. As a result, a majority of the FPC ruled that it did not have jurisdiction over sales by the Phillips Petroleum Co. to the interstate market. The State of Wisconsin and others appealed this determination by the Commission. It was this appeal that resulted in the Supreme Court's decision, and the Supreme Court's decision resulted in yet another effort by the producers to push legislation through Congress exempting them from regulation.

In 1956 congressional debate on deregulation centered around the Harris-Fulbright bill. To insure passage of this bill, the oil and gas industry had organized a massive lobbying and public relations effort funded with contributions totaling nearly $2 million. The debate, especially in the Senate, was long and furious. During debate in the Senate, Senator Hennings of Missouri carefully summed up his reasons for opposing the bill:

> What is being tested here today on the floor of the Senate is the power of the Federal Government to regulate monopoly;
>
> The country faces a concert of oil companies capable of monopoly control of the large blocks of reserves which are necessary to supply interstate utility markets. This means that either regulation in the public interest or monopoly domination will fix the ultimate cost of this utility service to consumers. If the proposal to amend the Natural Gas Act is carried out, it will be a victory for monopoly. The very fact that the big oil companies feel they can deny to utility markets the use of the country's natural gas reserves unless their terms are met is sufficient evidence, for me, at least, of the need for regulation in the public interest.

Yet, despite all of the reasonable and effective arguments posed by Senators Douglas, Kefauver, Morse, Humphrey, Hennings and Kennedy and despite the fact that Senatory Francis Case of South Dakota revealed that oil company representatives had offered him a bribe in return for his vote, the Harris-Fulbright bill was still passed by both Houses. President Eisenhower, however, recognized that the Democratic process had been violated by the attempted bribe of a U.S. Senator. In his veto message, Eisenhower pointed out that these activities

> include efforts that I deem to be so arrogant and so much in defiance of acceptable standards of propriety as to risk creating doubt among the American people concerning the integrity of govermental processes.

The producers tried again in 1958 and 1959 to force through passage of deregulation. In 1958, it did not come before the Senate for a vote, and in 1959 it was defeated. Following the election of President Kennedy, the newly-appointed Chairman of the FPC, Joseph Swidler began a serious effort to construct a "just and reasonable" regulatory framework which was fair to both producers and consumers. The producers, however, continued their battle against regulation. The period 1960-1968 was marked by constant clashes between a consumer-protection oriented Commission and anti-regulation producers who did their best to frustrate the FPC's efforts at regulation.

Former Republican Commissioner Charles R. Ross (who served from September 1961 to September 1968) recalled that

> . . . throughout this period the industry suffered badly because of its misguided attempts to force changes at the commission. The following actions all served to cause the Commission to question the industry's credibility; constant blatant attempts to pull power plays in Congress; repetitive instances of crying wolf; unwillingness to disclose complete and accurate industry data; failure to make the Natural Gas Advisory Council as effective an advisory voice as the Electric Advisory Council; the holding back of the pipeline companies from seeking to contest the higher wellhead rates and their threat to pull out of pipeline production if they did not get what they want; the delight of the industry at the rough handling that

> Chairman Swidler received at the hand of Albert Thomas, chairman of the House Appropriations Subcommittee on regulatory agencies; obvious efforts to influence President Johnson to dump me, as well as attempts to name the industry's own people to the commission; and the opposition to Canadian imports as a supplement to our reserves.

Nevertheless, despite producer opposition during this period the Commission settled on a methodology to set producer rates on the basis of production costs in major gas-producing geographical areas--the so-called area rate approach. This streamlined the previously unworkable method of setting producer rates on a company-by-company basis. During this period the producers repeatedly attempted, often successfully, to keep critical information from the Commission. For the most basic information, namely gas reserves, the FPC was forced to rely on unaudited industry data supplied by the American Gas Association. But despite the industry's reluctance to produce the necessary data, the FPC issued its first area rate decision, the Permian Basin decision, in August 1965. The prices established, one for "old" and one for "new" gas, were set at 14.5 cents per Mcf and 16.5 cents per Mcf, respectively. The prices were based on the historical production costs in the Permian Basin and allowed producers a 12 percent return on capital. The FPC's Southern Louisiana decision occured in September 1968 and closely followed the methodology established in the Permian decision. Also in 1968 the Supreme Court affirmed the Commission's decision in the Permian case. Both the Supreme

Court in the Permian Case and the Commission in the Southern Louisiana case rejected the producers' claims for rates higher than those set by the Commission, based on asserted declining reserves production ratios on the ground that new reserves exceeded production.

As in 1950 and 1957, when producers threatened Congress that failure to pass deregulation would result in declining gas production, the producers warned in 1968, following the Permian and Southern Louisiana decisions, that unless they received higher rates, there would be serious shortages of natural gas. In fact, since 1968 the producers have in a self-fulfilling prophecy. Following these two decisions, the gas producers began an all-out effort to end regulation. Increased gas deliveries to the nation's pipelines were shut off. The American Gas Association Reserve Committee in 1969 reported for the first time that new reserve additions in 1968 were less than the production for that year. The private gas distributors, who until 1968 had supported regulation, joined gas producers in saying increased incentives were needed to provide more gas. Finally, in November 1968 Richard Nixon was elected President of the United States. In his campaign Nixon has promised to reverse that he called the Democrats' "heavy-handed bureaucratic regulatory schemes." So, for the chairmanship of the Federal Power Commission, Nixon selected John Nassikas, a man who belived that the industry deserved higher prices and who spent his six years as chairman promulgating rules and decisions constantly upping natural gas prices and providing ways for the companies to avoid regulation. A number of attempts to administratively deregulate the price of gas were reversed by the Courts.

Within the past two years alone, the Courts have set aside at least six major pro-producer policies promulgated by the Commission.

1. FPC v. Texaco, Inc. 417 U.S. 380 (June 10, 1974)

In this case the FPC attempted to exempt small producers from regulation. The Supreme Court, however, decided that:

> "The requirements of the Act...do not distinguish between small and large producers with respect to just and reasonable rates. Even if the effect of increased small producer prices would make a small dent in the consumer's pocket, when compared with the rates charged by the large producers, the Act makes unlawful all rates which are not just and reasonable, and does not say a little unlawfulness is permitted.
>
> ****
>
> "In concluding that the Commission lacks the authority to place exclusive reliance on market prices, we bow to our perception of legislative intent."

2. Moss v. FPC, 502 F.2d 461 (August 15, 1974) [cert. granted]

In this case the FPc attempted to grant producers authority to abandon service in advance. The D.C. Circuit Court of Appeals held that:

> "Pregranted abandonment would leave a producer free to discontinue service to the interstate market, perhaps years after the original certification, with no contemporaneous obligation on the producer to justify withdrawal of service as consistent with the public convenience or necessity. We think Section 7(b) does not contemplate or authorize such a procedure.
>
> ****
>
> "We conclude that Section 2.75(e) of the Commission's Rule is unlawful and must be set aside."

3. MacDonald v. FPC, 505 F.2d 355 (September 19, 1974)

In this case the D.C. Circuti Court of Appeals ruled that the FPc could not permit rates for "old" gas 65% in excess of area ceilings without evidence of costs. The Court held that:

> "We perceive no reason why the special relief provisions in the Commission's area rate orders cannot be utilized to encourage needed gas exploration. But when the Commission permits an individual producer to depart from an area rate structure which has been developed with reference to average area-wide costs to provide producers a necessary but not excessive profit incentive for gas exploration, its regulatory trust requires it to give complete consideration to that producer's individual costs in order to ensure that the producer's profit margin is not thereby raised to an unreasonable level."

4. Consumers Union v. FPC, 510 F.2d 656 (October 7, 1974)

In this case the FPC attempted to permit rates for new gas 73% in excess of area ceilings without evidence of costs. The D.C/ Circuit Court of Appeals concluded that:

> "Commission's use of 1971 as a 'test year' in determining productivity was improper, on the record before it, and that rates could not be justified by noncost factors where gas reserves which were subject of the contracts had already been discovered and tapped and wells were on leases in the federal domain."

5. Public Service Commission v. FPC, 511 F.2d 338 (January 14, 1975)

In this case the FPC attempted to have pipelines, and through pipelines the consumers, provide venture capital to oil companies for exploration. The D.C. Circuit Court of Appeals held that:

> "The Federal Power Commission failed to engage in meaningful review, analysis and evaluation of the experience under the advance payments program, that data presented by the Commission as justification of its repeated extensions of the advance payment program did not provide adequate basis from which to determine whether its objectives were satisfactorily met at an acdeptable level of ultimate economic cost to the consumer, that the Commission failed to examine the effect of other methods of enhancing capital formation, that the Commission failed to properly focus on the difference between on-shore and off-shore advances, that the Commission failed to give reasoned consideration to the treatment which should be given advances which result in the acquisition of working interests..."

* * * *

> "There may be reason for the legislature to enact a deregulation for the natural gas industry, but so long as it prescribes a system of regulation by an agency subject to court review the courts may not abandon their responsibility to acquiescing in a charade or a rubber stamping of nonregulation in agency trappings."

6. Consumer Federation of America v. FPC, 515 F.2d 347 (March 13, 1975).

In this case the FPC attempted to exempt from regulation short-term sales of natural gas up to 180-days duration. The D.C. Circuit Court of Appeals held that:

> "Our examination of Order 491 convinces us that the Commission has exceeded its authority under the Act. In essence, it has attempted to remedy the shortfall of supply in the interstate market by authorizing a supplemental injection of large quantities of gas through sales freed from the constraints of meaningful regulation. We reject the FPC's claim that §7(c) supports this substantial, partial deregulation, and find that the Commission has neglected its rate control responsibilities under the Act."

There is no question that the major oil companies were happy with the new complexion of the FPC. They were now able to assist in dismantling the regulatory framework established by the previous commission's pro-consumer chairmen, Joseph Swidler and Lee White. And they could proceed with administration and FPC support for an all out, nationwide campaign, complete with "actual" gas shortages, to pressure Congress into deregulating natural gas prices.

The direction of the Nassikas Commission was clear from the beginning. Upon assuming the chairmanship Nassikas responding to the producers' request, immediately re-opened the Southern Louisiana case. In spite of the fact, or perhaps because of the fact, that the evidence presented by the producers indicated no major cost increases, the producers urged a "settlement" of the proceedings. In July 1971 the Nassikas Commission approved a settlement which (1) allowed price increases up to 54% above the "just and reasonable" rates set in the first Southern Louisiana case; (2) would result in rate increases to U.S. consumers of at least $4.75 billion; and (3) permitted some $350 million in refunds due to consumers under the first Southern Louisiana case to be either forgiven outright ($200 million) or retained by the producers ($150 million) through dedication of new reserves. In light of present-day producer claims, it is important to note that the settlement agreement to which all but two major producers (Standard of Indiana and Mobil) were a party contained the following commitment:

> "Each producer individually represents to the Commission that the ceiling prices [26 cents per Mcf] and other provisions contained herein *provide incentive for the exploration for and development of gas reserves* in the Southern Louisiana Area. In view of the nature of producing and finding hydrocarbons, it is unrealistic to expect producing companies to guarantee that the ceiling prices and other provisions contained herein will elicit a specific supply of gas; however, it is believed that the ceiling prices and other provisions contained herein will make funds available to the producing industry and create a regulatory atmosphere which should provide an incentive for a *substantial increase in exploratory and developmental activities and make a major contribution to bringing forth additional supplies of gas from the Southern Louisiana Area to meet the demands of all consumers supplied by this area.*" (emphasis added)

The Nassikas Commission clearly had no intention of creating of a stable regulatory environment. Following the Southern Louisiana decision, there was a vertible flood of decisions which continually provided producers with expectations of higher and higher prices. In addition, a number of Commissioners appointed by President Nixon publicly advocated deregulation to end the gas shortage, which their very actions were helping to create. Bruce Netschert, an economist with the well-known National Economic Research Associates, Inc. told the Senate Antitrust and Monopoly Subcommittee in May 1970:

> . . . the developing crisis is artificial in the sense that, as the gas producers themselves agree, there is plenty of gas left in the ground. It is simply not being developed and made available at an adequate rate . . . the gas producers, which is to say, the oil companies, expect that their point of view will prevail with the Federal Power Commission and so have everything to gain by holding off on gas finding and development until they get the price they ask.

Recently, the FPC set a nationwide area rate for new natural gas at approximately 52 cents per thousand cubic feet, which is 250% increase over the price in existence when Nassikas assumed the chairmanship in 1969. Despite these increases, sales to the interstate market have decreased and shortages have worsened.

It is important to note in this context that the major reasons supplies to the interstate market have been curtailed are (1) the lack of competition in the gas producer market; (2) withholding of supplies by producers; and (3) the failure of the Federal Power Commission to regulate on a "just and reasonable" cost of production basis and to enforce contracts between producers and pipelines.

THE LACK OF COMPETITION IN THE NATURAL GAS PRODUCER MARKET

The major producers and their allies argue that Congress should deregulate the price of gas to provide producers with sufficient incentive to explore for and develop new supplies. This argument is premised on the assumption that the natural gas producer market is competitive. But that assumption is false. The producer market is not competitive and deregulation would result in natural gas prices being set by a few major oil companies at non-competitive monopoly levels.

Free markets exist when there is competition among a large number independent of buyers. This is not the case in the natural gas producing industry. In this country there exist a number of major producing areas, such as, offshore Louisiana, the Permian Basin and Hugoton-Anadarko. Into these areas the major interstate pipelines have laid their gathering lines and have entered into contracts with producers. In all of the major producing areas, the largest producers control most of the available new gas supplies. In the Federal Offshore Louisiana Area, for example, the eight largest companies controlled 75% of the new gas supplies as of June 30, 1972. In the Permian Basin, the eight largest producers controlled 94.2% of the available new gas supplies. In some areas, such as, the Federal Offshore Texas Gulf Coast, only four producers contolled 100% of the new gas supplies. [Table I]

TABLE 1.—CONCENTRATION OF THE AVAILABLE NEW GAS SUPPLIES AS OF DEC. 31, 1971 AND JUNE 30, 1972[1]

(PERCENTAGE OF REPORTED UNCOMMITTED RESERVES CONTROLLED BY 4 AND 8 LARGEST PRODUCERS)[2]

Producing area	Dec. 31, 1971		June 30, 1972	
	4 largest	8 largest	4 largest	8 largest
Permian Basin	63.6	86.4	80.6	94.2
Hugoton Anadarko	76.6	94.5	62.6	83.3
Other Southwest	93.3	98.6	94.4	99.3
South Louisiana:[3]				
Onshore	96.9	99.6	92.3	98.4
Offshore (Federal)	57.0	83.3	49.6	74.9
Offshore (State)	84.5	100.0	94.9	100.0
Texas Gulf Coast:[4]				
Onshore	89.4	96.7	84.4	92.4
Offshore (Federal)	98.5	100.0	100.0	100.0
Offshore (State)	100.0	100.0	100.0	100.0
Rocky Mountain	63.4	82.9	70.4	86.0
Appalachian	99.6	100.0	100.0	100.0
Unclassified:				
Michigan	100.0	100.0		
California	95.4	100.0	94.3	100.0
Miscellaneous	87.7	99.9	98.0	100.0
Alaska[5]	93.9	99.9	93.9	99.9
Total United States[5]	51.4	75.9	51.0	73.9

[1] Concentration ratios are based on individual company reserve reports. To the extent that two or more companies report pro rata ownership shares of jointly held leases for which there is a single operation, the concentration ratios tend to underestimate the actual degree of seller concentration.

[2] Reports were obtained from 73 large producers. These producers provide most of the gas sold to interstate pipelines (e.g., in 1971 the top 22 supplied over 70 percent of all interstate gas). Nevertheless, to the extent that nonreporting small producers may have had significant volumes, the ratios reported here tend to slightly overstate actual market concentration.

3 Combined concentration ratios for the South Louisiana area are not available. Onshore represents 44 percent of the total, offshore (Federal) 53 percent, and offshore (State) 3 percent.

[4] Combined concentration ratios for the Texas Gulf Coast area are not available. Onshore represents 47 percent of the total, offshore (Federal) 51 percent and offshore (State) 2 percent.

[5] Does not include 26 trillion cubic feet in North Slope Reserves reported in the aggragate for all companies by one producer.

Moreover, the pipelines in each of their major supply areas are faced with only a small number of producers. For example, only four producers control 82% of the reserves available to the Cities Service Pipeline; 52% of the reserves available to Texas Eastern; 51% of the reserves available to Transcontinental, and so forth. [Table 2] This information was presented to the Senate Antitrust and Monopoly Subcommittee in 1973 by former FPC economist, Dr. John Wilson.

TABLE 3.—CONCENTRATION OF AVAILABLE NATURAL GAS RESERVES, BY PIPELINE SUPPLY AREA, JUNE 30, 1972

Pipeline	4-firm supply concentration ratio (percent)	Major supply araas	Percent of 1971 supply for each area
Columbia Gas	51.15	Southern Louisiana	81.7
		Texas Gulf Coast	5.2
		Appalachia	7.8
El Paso	61.33	Permian	54.2
		Hugoton-Anadarko	7.2
		Rocky Mountain	34.5
Michigan-Wisconsin	45.13	Southern Louisiana	65.0
		Hugoton-Anadarko	29.5
Lone Star	76.04	Other Southwest	33.9
		Texas Gulf Coast	35.6
		Permian	21.7
		Hugoton-Anadarko	8.6
Cities Service	81.93	Other Southwest	19.4
		Hugoton-Anadarko	80.6
Natural Gas Pipeline	49.32	Southern Louisiana	17.7
		Other Southwest	8.4
		Texas Gulf Coast	37.2
		Permian	15.5
		Hugoton-Anadarko	20.9
Northern Natural	71.60	Permian	50.4
		Hugoton-Anadarko	49.0
Panhandle Eastern	81.93	Other Southwest	30.7
		Hugoton-Anadarko	65.4
Southern Natural	47.91	Southern Louisiana	78.3
		Other Southwest	21.7
Tennessee	51.39	Southern Louisiana	75.3
		Taxas Gulf Coast	20.6
Texas Eastern	52.47	Southern Louisiana	55.9
		Othar Southwest	10.5
		Texas Gulf Coast	30.2
Texas Gas Trans	47.91	Southern Louisiana	90.6
		Other Southwest	9.6
Transcontinental	51.39	Southern Louisiana	82.5
		Texas Gulf Coast	17.4
Trunkline	51.35	Southern Louisiana	75.8
		Texas Gulf Coast	24.4
United	52.47	Southern Louisiana	77.9
		Other Southwest	12.9
		Texas Gulf Coast	9.3
Transwestern	71.60	Permian	76.3
		Hugoton-Anadarko	22.0

In addition, to the major producers' control over available gas reserves, they also control the leases in the offshore producing areas, where most of the large new reserves of gas are being found. Moreover, the major companies engage in numerous joint bidding and joint venture operations with each other, with pipelines and with smaller producers. In testifying before Congress on March 26, 1974, the FPC's former Assistant

Chief of the Office of Economics, Dr. David Schwartz explained why joint ventures prevent any meaningful competition in the production of natural gas:

> ...there is an extensive web of interdependence among major producers and among majors and smaller independent companies. The significane of these joint ventures goes beyond coordinated bidding for acreage, joint production and sale from this acreage. The most important aspect of joint ventures is the establishment of a commonality of interests which is antithetical to any potential rivalry or competition. For example, the evidence shows that only four of the 16 major petroleum companies with an interest in the Federal Offshore Domain own 50% or more of their producing leases independently. Conversely, 10 of the 16 own 80% or more of the offshore properties jointly with one another. More importantly, it is important to realize that very few companies outside of the top 16 have any independent holdings at all.

Dr. John Wilson presented the Senate Antitrust and Monopoly Subcommittee in June 1973 with the following Tables documenting the close interdependence of major producers with respect to their joint venture ownership of State and Federal leases:

TABLE 13.—JOINT OWNERSHIP OF STATE OF LOUISIANA PETROLEUM LEASES BY LARGE MAJOR PRODUCERS

Company and major partners	Number of jointly held state leases
Amerada-Hess:	
Phillips	36
Amoco	10
Sohio	2
Atlantic-Richfield:	
Cities	27
Continental	28
Getty	26
Union	10
Marathon	7
Texaco	4
Tenneco	4
Amoco	3
Chevron	2
Sohio	2
Cities Service:	
Atlantic	27
Continental	27
Getty	31
Exxon	2
Continental:	
Atlantic	28
Cities	27
Getty	27
Mobil	16
Exxon	13
Amoco	11
Sun	11
Tenneco	3
Gulf	3
Getty:	
Gulf	51
Atlantic	26
Cities	31
Continental	27
Exxon	27
Sohio	4
Tenneco	4
Amoco	4
Mobil	3
Sun	3
Shell	2
Texaco	2
Gulf:	
Exxon	62
Getty	51
Sohio	13
Shell	12
Amoco	7
Texaco	6
Chevron	6
Tenneco	5
Mobil	5
Continental	3
Sun	3
Phillips	2
Amerada	2
Marathon:	
Atlantic	7
Tenneco	3
Mobil:	
Continental	16
Amoco	8
Gulf	5
Sun	4
Texaco	4
Tenneco	3
Getty	3
Exxon	2
Phillips:	
Amerada	36
Sun	7
Amoco	3
Gulf	2
Shell:	
Gulf	12
Chevron	8
Exxon	5
Amoco	5
Texaco	5
Getty	2
Chevron:	
Shell	8
Gulf	6
Texaco	3
Exxon	3
Atlantic	3
Amoco:	
Texaco	11
Continental	11
Amerada	10
Mobil	8
Gulf	7
Shell	5
Sun	5
Tenneco	5
Exxon	4
Getty	4
Atlantic	3
Phillips	3
Union	3
Exxon:	
Gulf	62
Getty	27
Continental	13
Texaco	11
Tenneco	5
Shell	5
Amoco	4
Chevron	3
Mobil	2
Cities	2
Union	2
Sohio:	
Gulf	13
Getty	4
Atlantic	2
Amerada	2
Sun:	
Continental	11
Phillips	7
Amoco	5
Mobil	4
Getty	3
Gulf	3
Tenneco	3
Union	3
Tenneco:	
Exxon	5
Amoco	5
Gulf	5
Atlantic	4
Getty	4
Continental	3
Marathon	3
Mobil	3
Sun	3
Texaco:	
Exxon	11
Amoco	11
Gulf	6
Shell	5
Mobil	4
Atlantic	4
Chevron	3
Getty	2
Union	2
Union Oil:	
Atlantic	10
Amoco	3
Sun	3
Exxon	2
Texaco	2

TABLE 12.—JOINT OWNERSHIP OF FEDERAL OFFSHORE PRODUCING LEASES

Company	Number of leases	Independently owned	Major partners	Number of joint ventures[1]
THE MAJORS				
Amerada-Hess	15	0	Marathon	13
			Signal	14
			Louisiana Land	14
Atlantic-Richfield	94	3	Cities	85
			Getty	83
			Continental	87
			Tenneco[2]	4
			Standard Oil of California (Chevron).	2
			El Paso[2]	2
Cities Service	101	1	Atlantic	85
			Getty	93
			Continental	91
			Mobil	2
			Tenneco[2]	7
			Standard Oil of California (Chevron).	2
Continental	119	1	Atlantic	87
			Cities	91
			Getty	87
			Mobil	19
			Tenneco[2]	8
			Standard Oil of California (Chevron).	2
			Superior	2
			Transocean	2
			Southern Natural[2]	2
Getty	100	2	Atlantic	83
			Cities	93
			Continental	87
			Mobil	8
			Tenneco[2]	4
			Standard Oil of California (Chevron).	3
			Phillips	3
			Superior	2
			Transocean	2
			So. Natural[2]	2
			Allied Chemical	3
Gulf	51	34	Mobil	7
			Standard Oil of New Jersey (Exxon).	6
			Phillips	4
			Kerr-McGee	2
Marathon	18	0	Amerada	13
			Signal	13
			Louisiana Land	13
			Union	5
			Sun	3
Mobil	52	6	Continental	19
			Cities	8
			Getty	8
			Gulf	7
			Standard Oil of California (Chevron)	5
			Standard Oil of New Jersey (Exxon).	4
			Standard Oil of Indiana (Amoco)	4
			Pennzoil[2]	2
Phillips	16	3	Keer-McGee	7
			Gulf	4
			Getty	3
			Standard Oil of Indiana (Amoco)	3
			Sun	3
			So. Natural[2]	2
			Allied Chemical	3
Shell	68	64	Standard Oil of California (Chevron).	2
Chevron	105	86	Mobil	5
			Getty	3
			Atlantic	2
			Cities	2
			Continental	2
Amoco	60	3	Texaco	29
			Union	12
			S. Natural[2]	8
			Mobil	4
			Kerr-McGee	4
			Superior	4
			Tenneco[2]	3
			Phillips	3
			Pennzoil[2]	4
			Texas Eastern[2]	2
Exxon	52	43	Gulf	6
			Mobil	4
Sun	10	0	Burmah	11
			Murphy	10
			Kerr-McGee	4
			Union	3
			Phillips	3
			Marathon	3
			Cabot	3
			Diamond Shamrock	3
			Anadarko[2]	3
Texaco	55	16	Standard Oil of Indiana (Amoco)	29
			Tenneco[2]	9
Union Oil	37	18	Standard Oil of Indiana (Amoco)	12
			Marathon	5
			Superior	4
			Sun	3
			Texas Eastern[2]	2
SELECTED MEDIUM SIZED FIRMS				
Tenneco Oil[2]	51	24	Texaco	
			Continental	8
			Cities	7
			Consolidated[2]	6
			Columbia Gas[2]	6
			Texas Gas Trans.[2]	6
			Forest	6

Company	Number of leases	Independently owned	Major partners	Number of joint ventures[1]
Kerr-McGee	29	0	Phillips	7
			Cabot	12
			So. Nat.[2]	8
Cabot Corp	12	0	Sun	3
			Kerr-McGee	12
Pennzoil[2]	9	1	Standard Oil of Indiana	4
Consolidated[2]	33	0	Columbia Gas[2]	26
			Texas Gas Trans.[2]	25
			Forest	26
			Tenneco[2]	6
Columbia Gas[2]	33	0	Consolidated[2]	26
			Texas Gas[2]	27
			Forest	33
			Tenneco[2]	6
Texas Gas[2]	28	0	Consolidated[2]	25
			Columbia Gas[2]	27
			Forest	28
			Tenneco[2]	6
Forest Oil	34	0	Consolidated[2]	26
			Columbia Gas[2]	33
			Texas Gas[2]	28
			Tenneco[2]	6
Murphy-Ocean	32	1	Sun	10
			Burmah	21
Burmah	23	0	Sun	11
			Murphy-Ocean	21
Signal	15	1	Amerada	14
			Marathon	13
			Louisiana Land	14
Louisiana Land and Exploration	14	0	Amerada	14
			Marathon	13
			Signal	14
Superior	21	10	Standard Oil of Indiana (Amoco)	4
			Union	4
			Transocean	7
Transocean	14	0	Superior	7
			Hunt	7
			Placid	7
			Ashland	7
Hunt	17	3	Transocean	7
			Placid	9
			Ashland	7
Ashland	7	0	Transocean	7
			Hunt	7
			Placid	7
So. Natural[2]	15	0	Standard Oil of Indiana (Amoco)	8
			Kerr-McGee	8
Allied Chemical	3	0	Getty	3
			Phillips	3
Anadarko[2]	3	0	Sun	3
			Diamond Shamrock	3
Diamond Shamrock	4	0	Sun	3
			Anadarko[2]	3
Texas Eastern[2]	2	0	Standard Oil of Indiana (Amoco)	2
			Union	2
El Paso[2]	2	0	Atlantic	2
Placid	15	0	Transocean	7
			Hunt	9
			Ashland	7

[1] May add to more than total number of leases when three or more firms participate in individual joint ventures.
[2] This company or an affiliate is a major interstate gas pipeline.

Source: U.S. Department of the Interior.

Going beyond the economic evidence that there is little, if any, effective, or workable, competition in the natural gas producer market, it is important to note that all the courts, including the Supreme Court, which have reviewed FPC decisions, have ruled that because of the market imperfections and the lack of competition, regulation of the natural gas producer market is necessary to protect consumers "against exploitation by natural gas companies." The following excerpts are but a brief history of the Court's decisions in this area:

SUPREME COURT (1954) Phillips Petroleum Co. v. Wisconsin [347 U.S. 672]

"Regulation of the sales in interstate commerce for resale made by so-called independent natural gas producers is not essentially different from regulation of such sales when made by an affiliate of an interstate pipeline company. In both cases, the rates charged may have a direct and substantial effect on the price paid by the ultimate consumers. Protection of consumers against exploitation at the hands of natural gas companies was the primary aim of the Natural Gas Act."

FIFTH CIRCUIT (1958) Bel Oil Corp. v. FPC [255 F2d. 548]

"...evidence of unregulated prices in the field is not sufficient to warrant a finding by the Commission that a price comparable to them is just and reasonable within the intendment of the Natural Gas Act. Neither is evidence of the field price when coupled with the opinion of experts that the price must be high enough to provide an incentive for exploration and development of new sources of supply."

FIFTH CIRCUIT (1961) United Gas Improvement Co. v. FPC [290 F2d. 133]

"...the only justification for giving the Commission the duty to regulate prices was the determination by Congress that the producers have a supply that is so restricted in relation to demand that they have the economic power to bargain for prices that will be injurious to the public."

SUPREME COURT (1959) Atlantic Refining Co. v. PSC of New York [360 U.S. 378]

"The Act was so framed as to afford consumers a complete, permanent and effective bond of protection from excessive rates and charges...The overriding intent of the Congress [was] to give full protective coverage to the consumers as to price..."

SUPREME COURT (1968) Permian Basin Area Rate cases [390 U.S. 747]

"The field price of natural gas produced in the Permian Basin has in recent years steadily and significantly increased. These increases are in part the products of a relatively inelastic supply and steeply rising demand; but they are also symptomatic of the deficiencies of the market mechanism in the Permian Basin."

FIFTH CIRCUIT (1970) Austral Oil Co. v. FPC [428 F.2d 407]

"In a situation wherein the Commission has found that market imperfections tend to force prices to excessive levels, it would be self-defeating to regulate on the basis of market forces, and the most logical alternative is usually cost pricing."

D.C. COURT (1974) Federal Power Commission v. Texaco [417 U.S. 380]

"...in our view the prevailing price in the marketplace caanot be the final measure of "just and reasonable" rates mandated by the Act. It is abundantly clear from the history of the Act and from the events that prompted its adoption that Congress considered that the natural gas industry was heavily concentrated and that monopolistic forces were distorting the market price for natural gas. Hence, the necessity for regulation...

"In subjecting producers to regulation because of anti-competitive conditions in the industry, Congress could not have assumed that 'just and reasonable' rates could conclusively be determined by reference to market price. Our holding in Phillips implies just the opposite."

FIFTH CIRCUIT (1974) Macdonald v. FPC [

"The Commission determined early in its regulation of natural gas producers that protection of the consumer from these producers' market power could best be accomplished by setting rates tied to the producers' costs. In this way the producers' return on capital could be computed and held to that rate necessary to call forth needed gas supplies...The Commission's cost-based approach to regulation obtained unanimous judicial approval. As stated by Judge MacKinnon, '[W]hen the inquiry is whether a given rate is just and reasonable to the consumer, the underlying consideration is whether it is low enough so that exploitation by the producer is prevented.***[N]o factors apart from producers' costs are available to guide efforts to make that determination from the standpoint of the consumer.' City of Chicago v. FPC, 147 U.S.App.D.C. 312,332,458 F.2d 731,751, cert. denied, 405 U.S. 1074 (1971) (emphasis in orignial)."

FIFTH CIRCUIT (1975) Shell Oil Co. v. FPC [slip op. at 185]

> "Specifically, the producers base their argument for higher rates on a compromise between the FPC's new rate for natural gas and higher price of both oil and natural gas in the unregulated intrastate market. They argue that the national rate for regulated gas should equal the 'commodity value' of gas determined by comparison with substitutable fuels such as oil. In essence, these petitioners would have us set the price of natural gas at the rate that the market would bear. The commodity price of gas would most likely be set by the prevailing price of oil and the cross-elasticity of demand between gas and oil. To accept this free market 'commodity value' would be to eschew the congressionally mandated responsibility of rate regulation which is devised to reach a 'just and reasonable' rate. Fixing a 'just and reasonable' rate for a product sold in an inherently uncompetitive market requires more than mere subservience to national and international market forces."

The major oil companies' monopoly power can also be understood by the fact that despite higher prices and increased profits, they have steadily decreased their production. The following tables show the major companies' net income (worldwide and broken down to petroleum and natural gas operations in the U.S. where done), the rapid increase in regulated prices and the decrease in production. Unfortunately, the companies do not indicate their net income solely on the basis of natural gas production. But, we do know that the FPC allows a 15% to 18% rate of return, a rate which no producer has yet stated is insufficient incentive.

Net Income
(MILLIONS OF DOLLARS)

Companies	1974	1973	1972	1971
Exxon	$3,142.2	$2,443.3	$1,531.8	$1,516.6
Texaco	$1,586.4	$1,292.4	$ 889.0	$ 903.9
St. Ind.	$ 970.3	$ 511.2	$ 374.7	$ 340.6
Mobil	$1,047.4	$ 849.3	$ 574.2	$ 540.8
Gulf	$1,065.	$ 800.	$ 197.	$ 561.
Shell	$ 620.5	$ 332.7	$ 260.5	$ 244.5
Arco	$ 474.6	$ 270.2	$ 195.6	$ 198.7
Union	$ 288.0	$ 180.2	$ 121.9	$ 114.7
Phillips	$ 177.9	$ 98.7	$ 103.3	$ 90.7
Sun	$ 377.7	$ 229.7	$ 154.7	$ 151.6
Socal	$ 970.0	$ 843.6	$ 547.1	$ 511.1
Getty	$ 281.0	$ 142.2	$ 81.2	$ 130.9
Cities Service	$ 203.8	$ 146.9	$ 112.1	$ 104.5
Conoco	$ 327.6	$ 242.7	$ 170.2	$ 109.4
Amerda Hess	$ 201.9	$ 245.8	$ 26.0	$ 133.2
TOTAL	$11,734.3	$8,628.9	$5,339.3	$5,652.2

* Data derived from Companies' 1974 Annual Report.

Net Income

U.S. PETROLEUM & NATURAL GAS OPERATIONS
(MILLIONS OF DOLLARS)

Companies	1974	1973	1972	1971
Exxon	$1,021.0	$ 830.0	NA	NA
Texaco	$ 390.2	$ 436.0	NA	NA
St. Ind.	$ 637.9	$ 387.8	NA	NA
Mobil	$ 292.0	$ 258.0	NA	NA
Gulf	$ 527.0	$ 480.0	NA	NA
Shell	NA	NA	NA	NA
Arco	NA	NA	NA	NA
Union	NA	NA	NA	NA
Phillips	$ 177.9	$ 98.7	$ 103.3	$ 90.7
Sun	NA	NA	NA	NA
Socal	$ 273.0	$ 172.0	NA	NA
Getty	NA	NA	NA	NA
Cities Service	NA	NA	NA	NA
Conoco	$ 220.8	$ 131.7	$ 124.2	$ 124.4
Amerda Hess	NA	NA	NA	NA
TOTAL	$3,539.8	$2,794.2		

* Data derived from Companies' 1974 Annual Report.

WEIGHTED AVERAGE INITIAL RATES FOR ALL NATURAL GAS SOLD IN INTERSTATE COMMERCE

Federal Power Commission

[per Mcf]

1974	1973	1972	1971
50¢	39.3¢	29.7¢	28.4¢

PRODUCTION OF SALES OF NATURAL GAS*

MMcf/day

Companies	1974	1973	1972	1971
Exxon	5,312	5,758	5,952	5,885
Texaco	4,097	4,255	4,453	3,991
St. Ind.	2,864	3,091	3,154	3,058
Mobil	2,660	2,742	2,763	2,853
Gulf	2,305	2,632	2,882	2,887
Shell	2,101	2,366	2,598	2,715
Arco	1,739	1,913	1,946	1,989
Union	1,463	1,466	1,573	1,560
Phillips	1,433	1,481	1,534	1,566
Sun	1,974	1,973	1,972	1,971
Socal	1,253	1,336	1,429	1,451
Getty	1,195	1,236	1,235	1,230
Cities Service	1,115	1,090	1,051	1,021
Conoco	897	915	907	878
Amerda Hess	357	428	434	456
TOTAL	30,774	32,652	33,883	33,511

* Data derived from Companies' 1974 Annual Reports.

PRODUCER WITHHOLDING OF NATURAL GAS PRODUCTION

The major producers of natural gas are arguing that they need deregulation of natural gas prices so that they will have the incentive to produce gas for the interstate market. They argue that regulation of natural gas prices has resulted in less gas for the interstate market. There is, however, abundant evidence demonstrating that producers have both a motive and the means to withhold production. A Library of Congress report (July 7, 1975) points out:

> If a producer withholds production from a gas field of 100 billion cubic feet in reserves, a moderate sized gas field, rather than continuing it at current new gas rates of 55 cents, he can increase his total revenues from the field over 20 years, the average contract length, from $55 million at FPC rates to $200 million under deregulation. The possibility of this profit far exceeds the likely inflation until Congress decides on deregulation, or the interest on the investment in the lease and drilling costs. Even under continuing regulation by the FPC, which has raised rates an average of 30% per year, the dollar appreciation of the unproduced reserves exceeds the costs of letting them lie untapped. Moreover, the worse the shortage, the greater the pressure on Congress and the FPC is to raise prices.

During debate of S.2310 in the Senate, Senator Barlett (R-Oklahoma) conceded that there were gas supplies which were not being connected because the gas producers did not like the price. Senator Bartlett told Senator Glenn, ". . . at the present price there is gas that is not marketable, that the producer cannot develop the full area, that a pipeline company, or he himself is not willing to pay the price of a line to lay to a few wells. (Sept. 29, 1975)"

There are a variety of ways to delay production, slow development or otherwise withhold gas. According to Dr. Paul Davidson, Professor of Economics and Associate Director of the Bureau of Economic Research at Rutgers University,

> There is a mounting body of evidence that indicates that a significant amount of U.S. crude oil and natural gas (which would be profitable to produce even at current controlled prices) is being withheld by producers and other interested parties in the belief that wellhead prices of old oil and natural gas will be soon decontrolled an permitted to reach current exhorbitant cartel price levels. These withholdings are done under a number of different guises including:
>
> 1. An ususually large number of producible shut-in zones on offshore lands.
>
> 2. The setting of maximum allowable onshore at standards which are not based on enginerring considerations regarding MER and then constraining operators to produce at less than 100% of allowables.
>
> 3. The use of perpetual call clauses in farm out agreements which can give the majors the right to restrict natural gas and crude oil production of independents operating "farm out" properties.
>
> 4. The right of producers to produce at that rate of exploitation which they deem most efficient as long as they do not exceed allowables.
>
> 5. The rate that properties are leased by the federal government and the rate that leased properties are developed and brought on stream.
>
> [Testimony before the Subcommittee on Antitrust and Monopoly of the Committee on the Judiciary, United States Senate, 94th Congress, 1st Session, pp. 671-672, January 30, 1975]

John Jimison, a Library of Congress analyst, listed the following possibilities in his November 21 study:

> If a natural gas resource is thought definitely to exist, but is not explored in order to explore it later, withholding of gas may be accused. If exploration wells have determined that natural gas is present in quantity in a field, but production wells are not being drilled in a timely manner or the exploratory success has been hidden, withholding may be alleged. If natural gas has been found and partially developed, but proven reserves data made public significantly understate the amount of reserves in place, this may be considered by some a form of withholding. If full production from a lease was once occurring, but has unaccountably fallen below minimum contract quantities, withholding may be occurring. If unduly large amounts of gas available in reservoirs are being retained for future sales under a contract, when current shortages are unsatisfied, withholding may be involved.

A November 21, 1975 Library of Congress study concluded "that a natural gas producer with a typical gas field has a strong profit motivation not to commit gas to market at current regulated prices (even assuming that those prices will increase at 30% per year and that he will receive the increased prices as they are decided upon) because committing his field at deregulated prices is more profitable even after a four year wait."

Given the producer's incentive to withhold production in anticipation of higher prices, does he also have the means to withhold? The July 7, 1975 Library of Congress report indicates that "because of lax enforcement of production requirements by the U.S. Geological Survey and the easy extension of a producing lease by payment of a nominal 'delay rental', producers also have a means to delay production."

In the November 21 report, Jimison points out that "the standard private lease contains what is known as a 'shut-in gas clause', which permits the operator of a lease with a producible gas well to delay production indefinitely through payment of a very small sum."

Moreover, "a recent survey by the National Aeronautics and Space Administration for the United States Geological Survey found that only about 10% of offshore leases are being produced, but that USGS does not have the personnel to enforce production requirements, or the inclination, after years of merely assuring conservation of resources (July 7, 1975 Library of Congress report).

SPECIFIC EVIDENCE SUGGESTING PRODUCER WITHHOLDING

"In 1974 the Federal Power Commission reported that there were 168 leases in the federal offshore area which were classified by the USGS as "producible shut-in." According to the July, 1974 report there were 4.7 trillion cubic feet of proven reserves and 3.3 trillion cubic feet of probable reserves contained in these leases. 108 of these leases had been extended beyond their original 5-year lease term.

"In February, 1975 the Federal Power Commission reported that reserves totaling 8.5 trillion cubic feet in 1973 and 9.7 trillion cubic feet in 1974 were in a dedicated, but non-producing category. The FPC is currently investigating the reasons why this gas is not flowing into the interstate market.

"On October 14, 1975 an official of the Union Oil Company told an FPC attorney during a hearing (examining why the Transcontinental Gas Pipeline Co. was not receiving sufficient amounts of gas) that he believed that "even where it would be more economical to Union to accelerate production by drilling a new well, Union will not do so."

"In July, 1973 Mr. Douglas L. Bendell, an officer of the Okmar Oil Company was asked by an FPC attorney what his company would do with its gas if the FPC denied a requested price increase of double the then existing ceiling price. Mr. Bendell stated:

> The first thing we would do is look again at the intrastate market, because that is the obvious and quickest move. The second alternative would be not to market the gas at all . . . and take a certain risk that the appreciation of the reserves in the ground over 12 to 24 months, or however long, would more than compensate for whatever the value of the cash flow which we would get from the sale of the reserves over the term of the short-term contract would be. And then we have a third alternative which is a matter of some discussion. Uncommitted gas reserves now are apparently among the finest assets that a company can have -- an independent gas producing company -- and we are constantly, repeatedly, not only with respect to this property but with respect to any reserves we have -- we are being contacted by other gas producing companies, independents and majors, who are interested in buying the reserves in situ. They have expressed their willingness to bid on the come, so to speak, to take the gamble that the reserves would appreciate in the ground.

Also in 1973 the President of the Belco Petroleum Corporation told the FPC that "If it should turn out that the Commission decides that it cannot approve a considerably higher price for natural gas, then we expect that both ourselves and the rest of the industry will defer a lot of their exploratory drilling until they find out what happens in 1977."

The report of the Subcommittee on Oversight and Investigations concerning the decline of deliverability of natural gas at Garden City, Louisiana gas field owned by Exxon and Quintana Petroleum Corporation and from which Columbia Gas Pipeline Company receives 196 Mcf/day (5% of Columbia's total supplies) found "that the producers have not undertaken the drilling and other work projects necessary to maintain deliverability from the field," that"the current pricing regulations of the FPC permit the producers to recover their costs plus a reasonable rate of return," and that "the disparity between interstate and intrastate gas prices has caused the producers to shift resources to fields other than Garden City and has discouraged development of the field."

[Report by the Subcommittee on Oversight and Investigations of the Committee on Interstate and Foreign Commerce, House of Representatives, Congress, 1st Session, October 1973]

The report of the Subcommittee on Oversight and Investigations concerning the decline of deliverability of natural gas from the Bastian Bay Field located in Southern Louisiana and operated jointly by Getty Oil Co. and Tenneco., Inc. Bastian Bay is the 14th largest gas field in the United States with a producing capacity (as of December 31, 1974) of 314 million cubic feet per day. The subcommittee concluded that the two producers "have not undertaken sufficent drilling to maintian deliverability in this field, with the result that the field may be produced over a period of 62 years, instead of the 20 to 25 years originally contemplated or the industry standard of 15 to 20 years. The report concludes that the two producers have failed to resolve substantial differences of opinion on the geology of the field with the result that development has been delayed. It further concludes that the producers have failed to conduct studies of appropriate ways to accelerate production of the field, as recommended by one of their petroleum engineers. The report thus represents further evidence that gas producers which anticipate higher prices (as a result of contemplated deregulation of natural gas prices) have failed to do needed work in order to maintain deliverability."

[Report by the Subcommittee on Oversight and Investigations of the Committee on Interstate and Foreign Commerce, House of Representatives, 94th Congress, 1st Session, November, 1975]

The report by the Subcommittee on Oversight and Investigations on Cities Service Oil Company concluded that testimony given by Cities Service officials before the FPC with regard to the unavailability of a workover rig and tubing was false and misleading, and that the company's delays "resulted in disruption of deliverability of substantial quantities of gas needed by Transco during the critical winter season and thereby led to an increased shortage of gas to Transco and its consumer-customers."

[Report by the Subcommittee on Oversight and Investigations of the Committee on Interstate and Foreign Commerce, House of Representatives, 94th Congress, 1st Session, July 18, 1975]

According to the Federal Power Commission the Gulf Oil Corporation has not been fulfilling the terms of its warranty contract with the Texas Eastern Gas Transmission Co. Gulf is supposed to be supplying Texas Eastern with 500,000 Mcf/day, but in 1974 averaged 398,293 Mcf/day and during the first half of 1975 averaged 372,661 Mcf/day. Gulf has been saying that it underestimated its reserves, but former Commissioner Rush Moody did not buy this argument and stated on April 19, 1974, "Gulf made a consious choice in 1963 to rely upon its own reserve estimation and place behing that estimation a corporate obligation of performance. Texas Eastern, and this Commission, were induced by Gulf to accept Guld's reserve estimate without independent verification -- the inducement being, of course, Gulf's corporate promise to deliver specified volumes, at specified daily rates, and at specified prices." In short, Gulf has been withholding 128,000 Mcf/day, an action which has resulted in curtailments by Texas Eastern. The FPC has issued a show cause order to try to find out why Gulf is not complying with the terms of its contract.

In addition to the above specific reports, there have also been indications that producers have capped wells in order to take advantage of higher prices should deregulation be passed. In short, it appears that producers have used various means to slow down exploration, delay development, hold up production and constrain supplies in order to create a shortage situation wherein the Congress will feel compelled to deregulate prices.

It is interesting to note that the major producers attempted the same tactics during debate on deregulation in 1949-50 and in 1955-56. As a matter of record, on March 21, 1950, former Senator Paul Douglas pointed out that producers were "speculating on the fact that Congress and the President will put the Kerr bill [to prohibit the FPC from regulating producers] into effect. I have no objection to speculation as such, which is a part of the free-enterprise system, but I do object to speculating in commodities which are monopolistic in nature. However, it also seems obvious that most speculation in gas will end with the final disposition of this bill. If it shall be encacted, the gas now held off the market will be sold to interstate pipelines at monopoly prices. If we beat the bill, these holders will know that regulation will be forthcoming, and that there will be no point to charge whatever the traffic will bear."

In fact, Senator Douglas also pointed out in 1956 during debate on the Harris-Fulbright bill that producers were threatening to hold gas off the interstate market and were seeking intrastate markets. Because of the supply situation at that time, however, and because producers could earn a reasonable profit by selling gas in the regulated interstate market, the producers' threats proved groundless. However, at present the producers are able to make good their threats in the same way that the Arab oil producers were able to make good their embargo threats in 1973, while they failed in 1967. In both cases, there is an effort to use monopoly power to change public policy. As Senator Douglas stated on January 25, 1956 "Congress should not be influenced or intimidated by these bluffs, threats and veritable blackmail."

PRODUCERS UNDERREPORT AND MANIPULATE GAS RESERVE STATISTICS

One of the most critical questions that must be answered when dealing with the natural gas issue is whether the data on the nation's proved reserves of natural gas, which are supplied by the natural gas producers and which are relied upon by all government agencies dealing with natural gas, are reliable and valid. When there was a surplus of natural gas, prior to 1968, little public attention was paid to the question of reserve data and its reliability. But, in 1976, with the Federal Power Commission and the Federal Energy Administration predicting worsening shortages of natural gas, unless the price is deregulated, the accuracy, validity and reliability of the nation's data on gas reserves is critical. It is critical because the Federal Power Commission has relied on unverified and unaudited reserve data (submitted by an industry cognizant of the use of that data) to set the price of natural gas. And it is critical, because if it can be shown that the major oil companies and the American Gas Association are able to manipulate and/or underreport natural gas reserve statistics, then the entire premise for deregulation is demolished. One of the Administration's and the producers' main arguments is that regulation of natural gas prices has led to the downturn in reserve findings. However, the downturn in reserve findings is based on reports submitted by those producers who have a clear motive to report declining reserves. (To the extent the reserves additions are smaller and the finding rate lower, the resulting price goes up). And what is more important -- there is a substantial body of evidence indicating that the producers, in order to force higher prices from the FPC and deregulation from Congress, have indeed manipulated reserve data in such a way to create the impression that reserves have declined, when in fact they have not.

Before documenting the evidence demonstrating not only the producers' ability to manipulate and underreport natural gas reserve statistics, but also how such manipulation and underreporting has actually taken place, it is important to understand the evolution of this important issue. It is no coincidence that each time the Congress previously took up the issue of natural gas deregulation [in 1950 and 1956], the producers threatened that failure to enact deregulation legislation would result in natural gas shortages in the interestate market. During the 1956 debate on the Harris-Fulbright bill, Senator Paul Douglas observed,

> I have listened to and read many arguments that producers of natural gas will seek intrastate markets and will refuse to sell their gas in interstate commerce if the Fulbright bill does not become law. I do not expect that the threats now being made that consumers of natural gas in the nonproducing states will be deprived of natural gas in the future if the producers do not get their bill through this Congress, will be carried out any more than were the threats which were made at the time the Moore-Rizley and Kerr bills were under consideration.
>
> Statements were freely made by producers and proponents of similar legislation in the 80th and 81st Congresses that not another foot of natural gas would be sold in interstate commerce unless those bills were passed. But the producers each year continued to make such sales and have been making more and more sales ever since.
>
> [Cong. Rec., 1238, January 25, 1956]

After the producers failed to get their deregulation bill through Congress in 1956, the shortages that they predicted never occured. In fact, additions to reserves continued to exceed production all during the 1960's, that is, until 1968. The present natural gas shortage claims of the producers followed on the heels of the decision of the Supreme Court in 1968 in the Permian Basin Area Rate Case and the FPC's decision in the first Southern Louisiana Area Rate Case issued in September 1968. Both the Supreme Court and the Commission rejected the producers' claims for higher rates based on "reported" declining reserves to production ratios on the ground that new reserves exceeded production. It was following these two decisions,which had clearly rejected the producers' arguments,and it was following the election of Richard Nixon to the Presidency that the "gas shortage" was declared and implemented.

Producers began telling the pipelines that they did not have any additional reserves for sale and the American Gas Association Reserve Committee reported in May of 1969 that the new reserves added during the calendar year 1968 were less than the production for that year -- THE FIRST TIME ANY SUCH REPORT HAD EVER BEEN MADE! In the following year, 1969, the AGA reported a similar occurrence. As a result of these events, the data used by the Federal Power Commission in setting rates was seriously questioned. A 1969 Report by the FPC staff on gas supply noted that the entire report was based on industry-supplied data:

> Much of the factual base for this report is industry supplied data, including particularly the American Gas Association (AGA) proven reserve estimates and production information. The gas supply statistics of the American Gas Association are complied from the confidential records of individual independent producers and pipeline companies. Neither the confidential reserve data of these companies nor the exact method by which this data is summarized for the American Gas Association reports have ever been divulged to the Federal Power Commission. For purposes of this report we have accepted at face value all industry-furnished supply data. Our conclusion must therefore be weighed against the assumed accuracy of our data base.

Moreover, in March, 1970 the Fifth Circuit Court of Appeals in ruling on the first Southern Louisiana Area Rate Case also questioned the validity of the information used by the Commission:

> . . . this Court cannot itself evaluate the supply situation or determine what action is needed. We do not know whether the information that has reached us is correct or not.

It was clear in 1969 and it is clear today that the producers' claim of a "gas shortage" is directly linked to their attempt (1) to get higher prices before the Federal Power Commission and (2) to get Congress to deregulate natural gas prices. If the producers can show that there is a "shortage", then they believe they have also shown the need for higher prices or deregulation.

Early in 1969 the Federal Power Commission attempted to gather reserve and other vital information from the producers in the Southern Louisiana area. The Commission told the producers that they must produce the necessary reserve data in order to substantiate their claims of a real gas shortage. In response to the Commission's order, the staff drafted a proposed questionnaire which would have required the producers to reveal their gas reserve situation so that the Commission could independently assess the true nature of the gas supply problem. The producers, however, refused to supply the requested data.

The staff's argument was based on the fact that the producers were claiming that the "gas shortage" justified higher rates. The staff pointed out, "Absent demonstration of reserves availability and of the necessary price to elicit additional supply, those parties claiming the need for higher prices leave the Commission no way to guage either the validity of such claims or the amount of the justified increase, if any." During the FPC's deliberations on the reserves questionnaire, critical changes in personnel took place. On August 1, 1969 President Nixon's newly-pointed chairman, John Nassikas, took office.

Under Chairman Nassikas' new leadership, the Federal Power Commission did an about-face on its earlier March order and in December 1969 denied the issuance of the proposed reserved questionnaire. Thus, the new Commission by refusing to obtain the necessary reserve date decided to accept the industry's unsubstantiated claim of a "gas shortage." Moreover, all of the Nassikas Commission's subsequent actions were premised on this unsubstantiated "gas shortage", because at no time did the Commission obtain reserve data which was not supplied by the AGA.

Already in 1969 consumer groups argued that the FPC's blind acceptance of AGA reserve data information would have disastrous public policy consequences, because the information not only contained substantial discrepancies and inconsistencies with other FPC data, but it was prepared by producer representatives under a cloak of secrecy and neither the public nor the Commission had access to the underlying data by which this information could be checked, audited, or subject to cross-examination as to its truth and accuracy.

On December 8, 1971 the House Subcommittee on Special Small Business Problems issued a major report on the "Concentration by Competing Raw Fuel Industries in the Energy Market and Its Impact on Small Business." Among other conclusions, the Subcommittee found that:

> The air of secrecy imcumbent in the AGA's procedure for estimating gas reserves gives cause to the ratepaying public for challenging the reliability and use of such reserve estimates by the FPC in ascertaining the validity of a natural gas shortage.
>
> * * *
>
> The Commission's use of reserve estimates furnished by the natural gas industry serves only to derogate the public's confidence in the regulatory process and in those who are sworn to protect the public interest.

More questions were raised concerning the FPC's reliance on unaudited and unreliable AGA gas reserve data when Columnist Jack Anderson revealed in June of 1971 that a Staff memorandum of February 12, 1970 by the FPC's chief economist noted that there were substantial discrepancies between AGA Reserve data and the Pipeline Form 15's such that "two crucial sets of industry data on gas reserves 'can hardly be said to match each other'" and that "[t]he industry's estimates, which should be consistent, show 'surprisingly large differences' with many specific figures 'surprisingly wide apart'." The reports by Anderson also made reference to a memorandum of December 1, 1970 from the chief that "the evidence indicated errors up to 40 percent in some of the industry data" and a memorandum from the "Chief of the FPC producer division, who warned that 'the reliability of gas reserves estimates (by the industry) for any specific reservoir or field initially is suspect'."

A major discrepancy, for example, occured in reference to reserves in the offshore federal domain. The FPC's Form 15 reserve figures showed 34.1 trillion cubic feet of proved recoverable reserves in the offshore area in 1969, while the AGA figure for the same category of reserves showed only 24.1 trillion cubic feet. When comparing these two figures, it is critical to recognize that the Form 15's cover only the gas reserves dedicated in interstate commerce to the pipelines, while the AGA Reports are supposed to cover all gas reserves both interstate as well as intrastate. There is no data as to the intrastate reserves not reported on Form 15. Despite petitions by consumer groups to recosider its decision in refusing to issue a reserves questionnaire, the FPC continued to accept AGA reserve data as the basis for setting producer rates.

In response to the FPC's reluctance to issue a questionnaire and in response to the reports that the AGA's reserve data were unreliable, Senator Philip Hart, Chairman of the Senate Antitrust and Monopoly Subcommittee, on September 1, 1970 asked the Federal Trade Commission to conduct an investigation to determine whether there was withholding of gas reserves. Three years after the investigation had begun, the FTC reported to Senator Hart that it was "experiencing considerable difficulty in obtaining responses from most of the companies subpoenaed in the natural gas investigation." According to the report of former Director of the FTC's Bureau of Competition, James Halverson, before the Antitrust and Monopoly Subcommittee on June 23, 1973, the Bureau concluded "on the basis of documentation already" in its possession:

> 1. Serious underreporting by the natural gas producers to the Federal Power Commission of natural gas reserves has existed and continues to exist;
>
> 2. The procedure of reporting reserves through a subcommittee of the American Gas Association composed of employees of major producers could provide the vehicle for a conspiracy among the companies involved to underreport gas reserves . . .

In his testimony, Halverson also stated,

> The estimates of proved reserve to the South Louisiana Subcommittee of the AGA have been found to be significantly lower than the estimates of proved reserves reflected in the corporate compilations. Some of the estimates are approximately equal, but no corporate estimate has been found to date that is lower than the estimate submitted to the subcommittee.
>
> At times the estimate for a given field as reflected by company documents is as much as 10 times the estimate submitted for that same field at the same time to the American Gas Association. The Burean's investigation has uncovered numerous instances in which apparently substantial amounts of proved reserves of natural gas have been discovered in the Federal offshore areas and not produced.

> By that I mean that they have actually been found to exist by drilling a well but the tract has not been produced. These are proved, as we understand the meaning of the word "proved," but are not reported or are only nominally reported.

By August 1975, however, the FTC will had only received complaince with four of its eleven subpoenas. The other seven companies were able to tie the FTC up in court. Nevertheless, in a March 25, 1975 memorandum to the Commission, FTC lawyers recommended the issuance of a complaint against the American Gas Association and a number of major oil companies for "concertedly maintaining a deficient natural gas reserve reporting program which influences the price at which producers sell natural gas to interstate pipeline companies."

The FTC staff had concluded "that the AGA reserve reporting procedures are tantamount to collusive price rigging." The staff's investigation demonstrated that the AGA's Subcommittee on Gas Reserves in the Southern Louisiana Area was composed predominatly of representatives of the major oil companies.

> The members of the South Louisiana Subcommittee are paid by their producing company employees for the time spent doing AGA related work. Members are clearly seen as company representatives, not individual experts.
>
> * * *
>
> For some, representatives of nine major producers in the South Louisiana area have total control over gathering the reserve data.

On May 14, 1975, the former Director of the FTC's Bureau of Competition, James Halverson, also sent a memorandum to the Commission "strongly" urging that it issue a complaint charging the AGA and producers "with engaging in practices which are unfair to consumers."

Halverson argued that at the meetings of the AGA subcommittee:

> these representatives of the gas producers accept reserve estimates from each other without audit or review of the underlying raw reserve data which form the basis for the AGA estimates. The evidence received at investigational hearings further demonstrates the inconsistencies in the interpretation of the AGA definition of proved reserves of which the AGA member representatives are fully aware at the time they meet to compile the AGA aggregate reserve estimates. These inconsistent interpretations, which are reflected in intracorporate documents and can be established by comparing the testimony of various AGA representatives and company officials, lead to inconsistent and unreliable reserve estimates by the AGA. The evidence shows that the AGA representatives are aware of these discrepancies in the application of the AGA definition when they meet for the purpose of preparing the AGA reserve estimates, yet there is not a single adequate safeguard in the system to ensure against use of biased and manipulated data.
>
> Under these circumstances there is strong evidence of an unfair agreement, express or implied by the gas producers to maintain and participate in this inadequate system, irrespective of whether their conduct rises to the level of a conspiracy under Section 1 of the Sherman Act.

Moreover, Halverson pointed out that members of the AGA subcommittee have different defitions for proved reserves which could cause "a good deal of inconsistency in the reserve estimation process." Another problem with the reliability of AGA data concerns the inability of subcommittee members to gain access to raw data on reserves from fields in which his company has no interest." Halverson stated that "the AGA and its gas producer members make no audits of the reserve estimates submitted by each member of the Subcommittee."

. Among the serious anomalies, found by the FTC staff, were the statistics on reserves and successful drilling in 1968 and 1969 when the AGA revised reserve additions downward. Halverson described the staff's finding:

> To ascertain whether the sharp drop in the AGA reserve estimates for South Louisina for 1969 was associated with a decline in exploratory and development drilling in this area, the staff analyzed statistics published annually by the American Association of Petroleum Geologists. Successful exploratory gas wells rose from 342 in 1968 to 464 in 1969 and successful developmental gas wells rose from 2,556 to 3,135. In South Louisiana, successful exploratory gas wells declined from 45 in 1968 to 16 in 1969, while successful developmental gas wells increased from 162 in 1968 to 212 in 1969. The increase in developmental gas wells is especially significant because successful developmental drilling generally proves up reserves and should increase the proved reserve estimate, whereas successful exploratory drilling generally yields only probable reserves. Thus, the statistics point to a most unusual situation: a 37% increase in successful developmental drilling from 1968 to 1969, coupled with a 40-50% decrease in estimated reserve additions for 1969 for South Louisiana.

One of the most important findings of the FTC's investigation involved a comparison between the AGA estimates and estimates from the internal books or "ledgers" of those of the companies responding to the subpoenas. Halverson noted:

> . . . the comparisons of the estimates of the AGA and those found in the proved reserve ledgers show that the relationship between the proved reserve ledger and the AGA estimates is inconsistent over time in the magnitude and direction of deviation; however, there is, in the years critical to well-head price regulation, consistently lower AGA aggregate reserve estimates than proved reserve ledger estimates, and strongly suggest that the AGA system, which lacks assurances of access to data, lacks audits and review, and lacks sufficient guidelines on interpretation of definitions, has in fact produced an inconsistent and unreliable series of data.

On July 29, 1975 the Federal Trade Commission voted to continue its investigation, because said Chairman Lewis Engman"The Commission . . . has determined that it should have the interal reserve data of the seven natural gas companies which have resisted our subpoenas . . ."

In addition to the FTC's investigation and in response to mounting Congressional pressure, the Federal Power Commission also investigated the AGA's reserve reporting. In a report released in March 1974, the FPC's Office of Economics and the Bureau of Natural Gas found a total of 4,854 Billion cubic feet on 31 leases (4% of the offshore Louisiana total). This estimate was arrived at by the FPC's own engineers and geologists who performed actual tests on the wells.

This investigation of 31 leases revealed a discrepancy of 54% over the AGA's estimate of 3,150 Billion cubic feet for 900 offshore Louisiana leases! In addition, the FTC staff in its study, was able to cross-check these figures. Testifying before the House Subcommittee on Oversight and Investigation. FTC attorney Theodore Lytle stated that since they had access to the AGA's data on a field-by-field basis (which FPC investigation did not have), they were able to come up with a better comparison:

> We used the Federal Power Commission figures of 4.97 Tcf. Instead of having to use the aggregate AGA figure for all 900 leases we were able to get it down to roughly 58 leases on the AGA side. We could not be perfect because the AGA reports by fields. We found, as a matter of fact, that four of the leases that composed part of the FPC study were never reported by the AGA in 1971 and 1972, at least they did not submit any estimate to us for those leases. In short, in our comparison, using 58 blocks, we found a disparity of 2.7 trillion cubic feet. (emphasis added)

The AGA has had a difficult time accounting for this vast disparity in reserve estimates. As a matter of fact the AGA asked for a special meeting with FPC staff members to examine the FPC's data. FPC staff members agreed to show AGA officials their data, if the AGA would turn its data over to the FPC. The AGA refused.

Despite the proven and stated unreliability of the AGA reserve data, the Federal Power Commission continued to rely on AGA data in setting the latest National Area Rate. In this case, in which the FPC increased the rate of new gas to 52¢ per Mcf, an increase of more than 50% the FPC stated, "Productivity in terms of Mcf per foot drilled has the most significant impact upon the calculated new gas cost," and that "The productivity for any one year is calculated by dividing the annual non-associated gas reserve additions as reported by the American Gas Association by the total successful gas footage for that year." Because the FPC places such reliance on AGA reserve data in setting rates and because the major gas producers are not unaware of this reliance, it is important to recognize the changes in AGA positive and negative revisions of gas reserves estimates. The FPC itself observed (Op. No. 699-h) that

> For 1966 to 1968, net revisions increased from a positive 3 Tcf per year to a positive 4 Tcf per year. For 1969, net revisions were a negative 1.4 Tcf per year and revisions increased to a negative 5.3 Tcf per year, nearly a three-fold increase

The FTC staff investigation noted that the decrease in positive revisions in 1969 and the increase in negative revisions in 1973 by the AGA followed the opening of the Southern Louisiana Area Rate case in the first instance and the announcement of the formulation of a National Rate in the second.

In April 1974 the Federal Power Commission proposed the use of the so-called Form 40 for the collection of data under oath directly from the producers in a form which would allow the Staff to audit the data. The gas producers have challenged in Court the Commission's authority to collect reserve data on a reservoir by reservoir basis and have protested that the requirements for answering this form would be burdensome. The producers also argue that reservoir by reservoir reserve information is too confidential to be made public and that such information constitutes valuable "propriety property" the disclosure of which will hunt their competitive position.

The important point to note is simply -- if the producers refuse to come forward with reserve data which is in their possession and in a form which can be most easily audited in order to prove that a shortage does in fact exist, it can only be concluded that the interstate gas supply deficiency is contrived.

Just this past week, Dr. John Galloway, a special assistant on the staff of the Subcommittee on Oversight and Investigations, tetsified that when he compared the estimates for gas reserves contained in 153 pure gas fields made by the A.G.A. and the U.S. Geological Survey, he found that the U.S.G.S. total was 37.4 percent greater than the A.G.A. total. Galloway observed that if the same 37.4% discrepancy existed "nationwide, however, the A.G.A. reserve shortfall would amount to 102.7 trillion cubic feet of non-associated gas--enough to cover this winter's projected curtailments one hundred times over."

THE FEDERAL POWER COMMISSION'S FAILURE TO REGULATE

The problems of natural gas supplies and prices have come about not because the concept of regulation "to protect consumers from exploitation by natural gas companies" is a failure., but because over the past six years the appointed Commissioners have failed to carry out their responsibilities and have undermined "just and reasonable" regulation in the public interest. They have done this by attempting to administratively deregulate the price of natural gas, by abandoning the standard of cost-based regulation; and by refusing to enforce a number of critical regulations designed to protect the interstate market.

The major oil companies and the Administration have attempted to blame the so-called "natural gas shortage" on the Federal Power Commission's regulation of natural gas prices. While this attempt to discredit the Federal Power Commission has had widespread appeal, it has also been false and malicious for a number of fundamental reasons.

In 1969, after President Nixon took office, the major oil companies saw their chance to get Congress to deregulate the price of natural gas. The producers and pipelines brought pressure to bear on the private gas distributors, who previously had been among the strongest supporters of price regulation, to join in the fight. The support of the Nixon Administration was demonstrated early on when John Nassikas was appointed the new Chairman of the FPC. Nassikas told The New York Times on September 21, 1969, "We had the Kennedy round of tariff negotiations. What we need is a Nassikas' round of gas rate increases." It was clear that Nassikas and Nixon would be friendly to the interests of the major oil companies. Some suggest that this friendship blossomed into a "love affair." In any case, the new Commission under the chairmanship of John Nassikas was clearly pro-industry. Over the past six years, the FPC not only provided producers with higher and higher prices, but even went so far as attempting to administratively deregulate them. Thus, the Administration's argument that regulation has failed is due not to the failure of regulation per se, but the Commission's deliberate failure to regulate. With Commissioners and top level staff memebers in favor of deregulation, it is clearly understandable why regulation has not worked.

Testifying before the Senate Antitrust and Monopoly Subcommittee on June 26, 1973, Rep. George E. Brown clearly summarized the problem:

> We have been repeatedly warned by both scholars and practical politicans that independent regulatory agencies are in constant danger of being taken over and controlled by the very industries that they are charged with regulating. I submit to you that recent events and the facts uncovered by both my staff and deligent investigative reporters indicate that this has happened to the Federal Power Commission. This demise of the Federal Power Commission as an independent and vigorous regulator and planner has permitted the energy shortage to deepen in severity with untold cost to the American consumer.
>
> ****
>
> ... we have a regulatory Commission made up of commissioners so industry oriented that they publicly advocate that the Commission should give up its function. Instead of enforcing statutes enacted by the Congress, and providing consumer protection against monopoly exploitation, they have chosen to use their high office to undermine public surveillance of the industry, and to serve private oil and gas interests.
>
> ****
>
> What sensible, self-interested gas producer, having heard that the Chairman of the Federal Power Commission intends to push for substantially escalated gas prices, or who knows that all of the members of the Federal Power Commission favor deregulation, would sell his gas today, rather than holding it off the market and getting two or three times as much as soon as Chairman Nassikas and his colleagues are able to implement their plans? If, as these gentlemen advocate, we deal with the gas shortage by inflating petroleum industry profits to record levels, are we not creating an incentive for permanent shortages?

> ... the solution to our gas shortage is not deregulation. What is needed is effective consumer-oriented regulation; regulation that requires oil companies to produce gas rather than sitting on it; regulation that results in reasonable prices, proper allocation of reserves to the public and that avoids massive profit windfalls. That is the only obvious solution to the oil industry's monopolistic excesses.

The Administration and the Federal Power Commission for the past six years have argued that the way to solve the shortage of natural gas is to allow producers to charge whatever the "market will bear." Yet, a brief history of gas pricing will demonstrate the utter fallacy of this argument.

Prior to the advent of federal regulation in 1954, gas sold for slightly less than 10¢ per Mcf. During the Eisenhower era, from 1954 to 1961, both price and supply increased dramatically: the average interstate price increased from 9.5¢ per Mcf to 16.5¢ per Mcf, while the volumes sold in interstate commerce increased from 5 trillion cubic feet to 8 trillion cubic feet. During the Kennedy-Johnson era, from 1961 to 1969, prices were held relatively constant, increasing from 16.5¢ to 17.5¢ per Mcf, but again the volumes sold interstate increased dramatically, from 8 trillion cubic feet to 13.5 trillion cubic feet. The present Nixon-Ford era--during which the Federal Power Commission has been staffed by Commissioners none of whom believes in regulation--has witnessed the worst of all possible results: an unprecedented increase in price, from an average 17.5¢ per Mcf in July 1969 to a December 1974 average of 32.5¢, with the growth in interstate sales halted and indeed declining slightly after 1972. And under existing FPC policy, the average price will continue to rise sharply, since the FPC has recently raised the "new gas" price--which is, in fact, applicable to much old gas--from 20-26¢ per Mcf to 57¢ per Mcf (including all allowable adjustments).

Thus for at least fifteen years, until 1969, regulation of natural gas prices by the Federal Power Commission did work to assure the nation an adequate supply at reasonable prices. This can be clearly demonstrated by the following table which Dr. David Schwartz, former Assistant Chief of the Office of Economics of the Federal Power Commission, introduced in June of 1973 to the Senate Antitrust and Monopoly Subcommittee.

TABLE I.—NATURAL GAS RESERVE, PRODUCTION, AND PRICE DATA, 1963–72

	Natural gas reserve and production data [1]				
	Net production [3]	Total reserve additions [2]	Findings to production ratio	Weighted average initial contract price [3] [4]	Weighted average rate ceilings for new gas [4] [5]
1963	14.5	18.1	1.2	17.0	18.2
1964	15.3	20.1	1.3	16.2	18.1
1965	16.2	21.2	1.3	17.4	18.1
1966	17.5	19.2	1.1	17.4	18.1
1967	18.4	21.1	1.1	18.6	18.1
Average, 1963–67	16.4	19.9		17.3	18.1
1968	19.3	12.0	.6	19.0	17.9
1969	20.6	8.3	.4	19.7	17.6
1970	21.8	11.1	.5	20.8	18.0
1971	21.9	9.4	.4	25.8	24.6
1972	22.4	9.4	.4	30.4	24.9
Average, 1968–72	21.2	10.0		23.1	20.6
Percent change	29.3	−49.7		33.5	13.8

[1] Total United States exclusive of Alaska.
[2] Trillion cubic feet.
[3] At 14.65 lb. $in.^2$.
[4] Cents per thousand cubic feet.
[5] FPC orders and opinions.

Source: "Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada," American Gas Association. Exhibit No. 24, Docket No. AR69-1, Southern Louisiana Area; FPC Form 301B, Billing Statements and Certificate Applications.

Dr. Schwartz explained that the significance of this table "is the marked increase in production, or demand for gas, in contrast to new reserve additions." He stated further:

> A comparison of the average 5-year earlier period with the 1968-72 5-year average indicates net production going up by more than 29 percent; total reserve additions going down by approximately 50 percent in response to a 33.5-percent increase in weighted-average initial contract prices and 13.8-percent weighted-average new-gas ceiling prices.
>
> What appears to be an inverse relationship between price and new supplies--what economists would call negative elasticity--is the puzzling question that emerges from these figures. The normal expectancy would be for supply to increase as price increases and even if the elasticity of supply response is less than the price increases--that is, supply is relatively inelastic--we would still expect something other than negative elasticity.
>
> I think the answer to this apparent contradiction lies elsewhere. With the anticipation of significant price increases that have existed since 1968, one would expect lower exploratory and developmental activity.

> Put another way, it is more profitable to keep gas in the gound rather than to explore, develop, and produce new supplies for commitment to contract as long as the expected present value of future returns is greater than current rates of return that could be earned at existing price levels.
>
> In other words, producers would prefer to speculate that price increases in the future will result in higher returns than commitment of gas at current price levels.

Adding data for 1973 and 1974, the trends described by Dr. Schwartz have worsened, indicating further that the FPC's non-regulation has led to further speculative withholding by producers in anticipation of either higher prices or deregulation:

Net Production		Total Reserve Additions	Findings to Production Ratio	Weighted Average Initial Contract Price	Weighted Average Rate Ceilings For New Gas
1973	22.5	6.5	.3	39.3	24.6
1974	21.2	8.3	.4	49.9	42.9

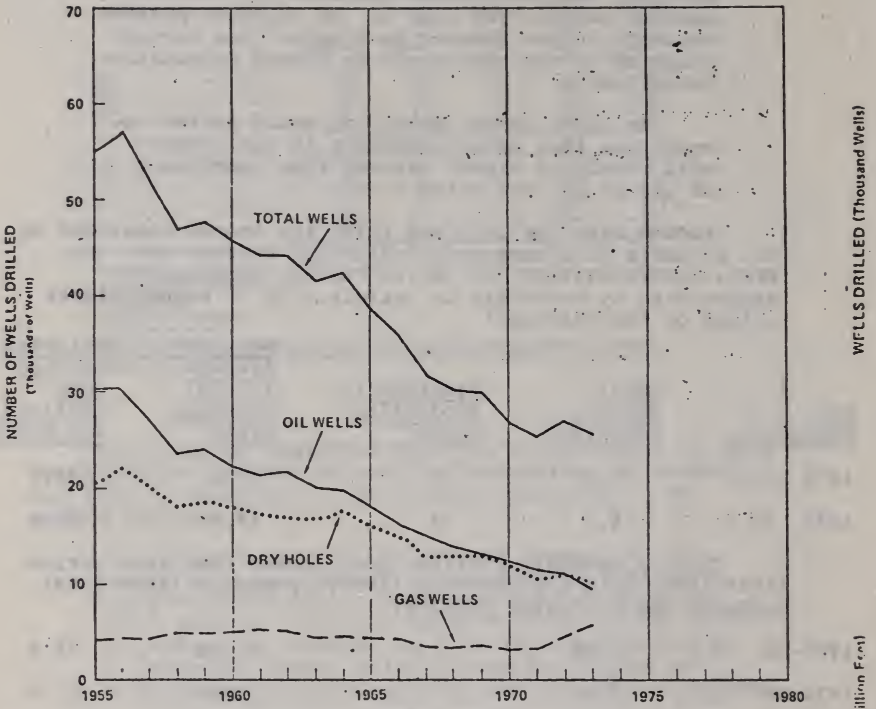
Thus, a comparison of the most recent five-year period (1970-1974) with the previous five-year period (1965-1969) produces the following results:

1965-69	18.4	16.36		33.24	18.0
1970-74	21.96	8.94		18.42	27.0

Therefore, while the average price for new gas increased by 50%, and while the average initial contract price increased by 86%, reserve additions declined by 45% with production increasing only by 19%!

The producers' argument that regulation has not provided sufficient incentive to drill for natural gas is misleading and is contradicted by the facts. The following chart clearly indicates what has happened in terms of drilling activity over the past 19 years. While the price of oil was, for the most part, unregulated, drilling for oil has been declining steadily and sharply. Yet, the drilling for natural gas, which has been regulated since 1954 has shown no decline! Obviously, because gas has been so inexpensive to produce, despite a regulated price, producers have had sufficient incentive to drill.

CHART V-A
TOTAL U.S. DRILLING ACTIVITY - OIL, GAS, DRY AND
TOTAL WELLS DRILLED 1955 - 1973



OIL AND GAS WELLS

Yr.	Oil	Gas	Yr.	Oil	Gas	Yr.	Oil	Gas	Yr.	Oil	Gas	Yr.	Oil	Gas
55	30,432	4,266	60	22,233	5,129	65	18,065	4,482	70	12,398	3,225	75		
56	30,528	4,531	61	21,413	5,459	66	16,216	4,321	71	11,510	3,399	76		
57	27,364	4,475	62	21,727	5,353	67	15,073	3,602	72	11,139	4,777	77		
58	23,774	5,005	63	20,135	4,570	68	13,982	3,329	73	9,555	5,894	78		
59	24,043	4,931	64	19,905	4,694	69	13,213	3,656	74			79		

DRY HOLES AND TOTAL WELLS 1/

Yr.	Dry	Total	Yr.	Dry	Total	Yr.	Dry	Total	Yr.	Dry	Total	Yr.	Dry	Total
55	20,452	55,150	60	18,185	45,547	65	16,226	38,773	70	11,161	26,784	75		
56	22,111	57,170	61	17,382	44,254	66	15,193	35,730	71	10,448	25,357	76		
57	20,156	51,995	62	17,078	44,158	67	12,958	31,633	72	11,171	27,087	77		
58	18,102	46,881	63	16,762	41,467	68	12,954	30,265	73	10,017	25,466	78		
59	18,589	47,563	64	17,694	42,293	69	13,076	29,945	74			79		

Source: World Oil

1/ Excludes service wells.

Federal Power Commission, Gas Supply Indicators, Washington, D.C. 1974

It is, therefore, obvious that beginning in 1970, the Nixon appointees on the Commission accepted the oil industry's premise that the way to avoid impending shortages of natural gas was to allow higher prices; and when these higher prices led, not to increased supplies, but to even greater shortages, the Commission responded with still higher prices. Admittedly, federal "regulation", as it is being implemented by the FPC, is not working and cannot be expected to work, but that is hardly the fault of the regulatory statute, and is no argument for its repeal.

The Federal Power Commission's unwillingness to enforce the consumer-protection standards of the Natural Gas Act have been demonstrated by the number of times the Courts have cited the Commission for the Natural Gas Act. Within the past two years alone, the Courts have set aside at least six major pro-producer policies promulgated by the Commission.

1. FPC v. Texaco, Inc. 417 U.S. 380 (June 10, 1974)

In this case the FPC attempted to exempt small producers from regulation. The Supreme Court, however, decided that:

> "The requirements of the Act...do not distinguish between small and large producers with respect to just and reasonable rates. Even if the effect of increased small producer prices would make a small dent in the consumer's pocket, when compared with the rates charged by the large producers, the Act makes unlawful all rates which are not just and reasonable, and does not say a little unlawfulness is permitted.

****

> "In concluding that the Commission lacks the authority to place exclusive reliance on market prices, we bow to our perception of legislative intent."

2. Moss v. FPC, 502 F.2d 461 (August 15, 1974) [cert. granted].

In this case the FPC attempted to grant producers authority to abandon service in advance. The D.C. Circuit Court of Appeals held that:

> "Pregranted abandonment would leave a producer free to discontinue service to the interstate market, perhaps years after the original certification, with no contemporaneous obligation on the producer to justify withdrawal of service as consistent with the public convenience or necessity. We think Section 7(b) does not contemplate or authorize such a procedure.
>
> ****
>
> "We conclude that Section 2.75(e) of the Commission's Rule is unlawful and must be set aside."

3. MacDonald v. FPC, 505 F. 2d 355 (September 19, 1974)

In this case the D.C. Circuit Court of Appeals ruled that the FPC could not permit rates for "old" gas 65% in excess of area ceilings without evidence of costs. The Court held that:

> "We perceive no reason why the special relief provisions in the Commission's area rate orders cannot be utilized to encourage needed gas exploration. But when the Commission permits an individual producer to depart from an area rate structure which has been developed with reference to average area-wide costs to provide producers a necessary but not excessive profit incentive for gas exploration, its regulatory trust requires it to give complete consideration to that producer's individual costs in order to ensure that the producer's profit margin is not thereby raised to an unreasonable level."

4. Consumers Union v. FPC, 510 F. 2d 656 (October 7, 1974)

In this case the FPC attempted to permit rates for new gas 73% in excess of area ceilings without evidence of costs. The D.C. Circuit Court of Appeals concluded that:

> "Commission's use of 1971 as a 'test year' in determining productivity was improper, on the record before it, and that rates could not be justified by noncost factors where gas reserves which were subject of the contracts had already been discovered and tapped and wells were on leases in the federal domain."

5. Public Service Commission v. FPC, 511 F.2d 338 (January 14, 1975)

In this case the FPC attempted to have pipelines, and through pipelines the consumers, provice venture capital to oil companies for exploration. The D.C. Circuit Court of Appeals held that:

> "The Federal Power Commission failed to engage in meaningful review, analysis and evaluation of the experience under the advance payments program, that data presented by the Commission as justification of its repeated extensions of the advance payment program did not provide adequate basis from which to determine whether its objectives were satisfactorily met at an acdeptable level of ultimate economic cost to the consumer, that the Commission failed to examine the effect of other methods of enhancing capital formation, that the Commission failed to properly focus on the difference between on-shore and off-shore advances, that the Commission failed to give reasoned consideration to the treatment which should be given advances which result in the acquisition of working interests..."

* * * *

> "There may be reason for the legislature to enact a deregulation for the natural gas industry, but so long as it prescribes a system of regulation by an agency subject to court review the courts may not abandon their responsibility to acquiescing in a charade or a rubber stamping of nonregulation in agency trappings."

6. Consumer Federation of America v. FPC, 515 F. 2d 347 (March 13, 1975).

In this case the FPC attempted to exempt from regulation short-term sales of natural gas up to 180-days duration. The D.C. Circuit Court of Appeals held that:

> "Our examination of Order 491 convinces us that the Commission has exceeded its authority under the Act. In essence, it has attempted to remedy the shortfall of supply in the interstate market by authorizing a supplemental injection of large quantities of gas through sales freed from the constraints of meaningful regulation. We reject the FPC's claim that §7(c) supports this substantial, partial deregulation, and find that the Commission has neglected its rate control responsibilities under the Act."

Despite numerous reversals in the Courts, a determined and ingenious Commission has found other ways to set higher prices, with the result that the oil companies collect ever-higher revenues, the consumer pays ever-higher prices, and the shortage--so profitable for the oil industry--has continued to widen and deepen. Given this past history, it can no longer be argued on a rational, objective basis that higher prices will produce more gas. On the contrary, the industry has learned well that so long as the government's response to energy shortages is to allow ever higher prices, the industry's financial interest lies in maintaining the shortage. As a matter of fact, various executives of major oil companies have stated publicly that their sharply increased earnings in 1974 were the result of higher prices that more than offset decreased production, and that they expect continued high earnings in the future from higher prices despite declining production.

Before enumerating some of the more blatant examples of the Nassikas Commission's failure to carry out its regulatory responsibility, it is important to identify the large number of decisions made by that Commission which allowed the continual escalation of price and producer expectations. The following are a list of actions taken by the FPC since 1969 to provide the necessary "economic incentive" to the industry to alleviate the gas supply situation.

1. October 3, 1969 [Opinion No. 567].

The FPC allowed producers to charge higher rates for new gas-well gas to encourage exploration and production from newly-discovered reservoirs on previously dedicated acreage, but which were discovered as a result of a new and separate drilling program.

2. October 7, 1969 [Opinion No. 568].

The FPC indicated that it would permit area rates for gas produced by pipeline companies, formerly priced at cost of service. This new policy was supposed to encourage intensified natural gas exploration by interstate pipelines.

3. December 15, 1969.

The Commission broadened the AR69-1 area rate proceeding to include both onshore and offshore gas from the Southern Louisiana area and denied the Staff's proposed questionnaire which would have required producers to disclose thier gas reserves situation.

4. June 17, 1970.

The FPC initiated a "second round" area rate proceeding in Docket Nos. AR70-1 and R-389 which instituted an investigation of existing prices in the Permian Basin Area and to determine whether higher rates were required for future supplies of natural gas dedicated to the interstate market. In this proceeding the FPC stated that it would accept for consideration applications for certificates of public convenience and necessity for sales of natural gas even though the stated rate may be in excess of the ceiling or guideline rate.

5. July 17, 1970, [Docket No. R-389A].

The FPC opened a nationwide investigation to set rates via rulemaking procedures rather than adjudicatory hearings for future producer sales throughout the United States.

6. August 26, 1970. [Order No. 408].

The FPC issued revised accounting procedures for research and development expenses. The changes allowed the regulated companies more latitude in the recovery of R&D costs and were calculated to stimulate technological developments in the natural gas industry.

7. September 18, 1970. [Opinion No. 586].

The FPC set rates for gas produced in the Hugoton-Anadarko area, by approving a settlement proposal filed by a group of producers early in 1970. The FPC stated that the settlement would encourage exploration for and development of additional gas supplies from the area at a time when the nation is facing critical gas supply problems.

8. October 2, 1970. [Order No. 410].

The FPC amended its Uniform System of Accounts to permit unrecovered advance payments to be included by pipelines in their rate base as part of working capital.

9. October 1970. [Order No. 411]

The FPC established rates for the Appalachian and Illinois Basin areas. For the first time, the FPC set rates by a rulemaking proceeding, in order to expedite the matter so that producers would be assured of the new high rates at the earliest possible time.

10. October 5, 1970. [Docket No. R-403].

The FPC issued a rulemaking notice proposing to adopt full-cost accounting for exploration and development costs incurred by pipeline companies on natural gas leases acquired on or after October 7, 1969. The objective of the proposal, which was adopted on Novenber 5, 1971 in Order No. 440, was to encourage pipeline companies to commit additional capital for gas exploration by postponing charges against income until revenues are received from producing wells.

11. December 10, 1970. [Order No. 418].

The FPC amended its Regulations under the Natural Gas Act to permit independent producers to sell natural gas to pipelines for emergency purchases for periods up to 60 days without first obtaining certificate authorization from the Commission.

12. February 18, 1971. [Order No. 423].

The FPC established as a matter of General Policy a suspension period of only one day from the proposed effective date of a rate change filing made by an independent producer unless the Commission impose a longer suspension period. The former suspension period was five-months which meant that producers could not collect the increased revenues during that entire period.

13. March 18, 1971. [Order No. 428].

The FPC exempted all existing and future sales by so-called "small producers" (i.e. those with sales of less than 10,000,000 Mcf of gas per year) from direct rate regulation.

14. May 6, 1971. [Opinion No. 595].

The FPC set higher rates for gas produced in the Texas Gulf Coast, stating that it was imperative to provide incentives to find and dedicate gas to the interstate market. Accordingly, the FPC found it in the public interest to offer incentives to the producers above and beyond the area rates. The Commission stated that without such incentives, only negligible amounts of gas may be obtained by interstate pipelines in the forseeable future.

15. July 15, 1971. [Order No. 435].

The FPC set new firm, non-refundable ceiling rates for sales of gas under contracts dated after June 17, 1970 in the Rocky Mountain area, at a price level designed to create greater incentives for producers to seek new supplies. The FPC declared that the Rocky Mountain area was the only remaining onshore region, except Alaska, of major potential with extensive areas still undrilled.

16. July 16, 1971. [Opinion NO. 598].

The FPC set new, higher ceiling rates for the Southern Louisiana area and provided for a system of incentives to promote dedication of gas reserves to the interstate market. The FPC's opinion accepted the provisions of a settlement proposal. The incentive plans tied price escalations to the attainment on an industry-wide basis of specified reserve dedication goals. The incentives also allowed individual producers to reduce their obligations through commitment of new gas reserves to the interstate market.

17. October 29, 1971. [Opinion No. 607].

The FPC set higher ceiling rates for natural gas produced in the "Other Southwest Area". The Opinion provided for the escalation of area ceilings, as well as incentives to the producers to find gas and dedicate it to interstate commerce. The FPC also allowed producers to discharge any refund obligations (i.e. for rates in excess of the area rate) by dedications of additional gas reserves to interstate commerce.

18. August 3, 1972. [Order No. 455].

The FPC adopted a new rule which would permit producers to apply for rates higher than the applicable area rates. The new rule called the "optional procedure" was based on the assumption that higher prices were necessary to alleviate the natural gas shortage.

19. December 12, 1972. [Opinion No. 639].

The FPC allowed producers in the Appalachian area to use the optional procedure previously established by the Commission for sales of new gas to the interstate market. The Commission abandoned the area rate approach to provide the producers with additional incentives to explore for and develop new gas supplies.

20. May 30, 1973. [Opinion No. 659].

Under its Optional Pricing Procedure the FPC granted Belco Petroleum, Texaco and Tenneco an initial rate of 45¢ per Mcf which was 73% above the area rate. Moreover, the FPC defended the use of non-cost factors in determining the rate.

21. August 7, 1973. [Docket AR70-1].

The FPC increased the rates for old and new gas in the Permian Basin. It set a flowing gas rate of 23¢ per Mcf (including 3.5 cents per Mcf for exploration and development), a price which was 8.5¢ per Mcf higher than the first Permian decision in 1965. Moreover, it increased the price for new gas from 16.5 cents to 35.0 cents per Mcf.

22. September 14, 1973. [Order No. 491].

The FPC allowed producers to sell gas at rates above the existing ceilings for a period of up to 180 days.

23. June 21, 1974. [Docket 389-B].

The FPC proposed a 42¢ rate as a new ceiling price for all gas wells drilled after January 1, 1973, with an annual 1¢ per Mcf escalation. Later the FPC increased this rate to 51¢ per Mcf. This rate representas a 100% increase over the price judicially affirmed in the Second Southern Louisiana case.

24. August 28, 1975. [Opinion No. 533].

The FPC allowed certain high priority industrial and commercial users to purchase gas at unregulated rates directly from producers.

25. December 31, 1975. [Opinion No. 749].

The FPC allowed producers to increase the price of "old" gas an average of 21% or 4.8¢ per Mcf above the previous average price. The increase will cost an additional $500 million per year. The new Nationwide Rate for "old" gas replaces the various "old" gas area rates.

Not surprisingly, each and every one of the above steps was calculated to increase the profitability of selling natural gas in interstate commerce, and as in the case of the new, higher rates set for the Southern Louisiana area, the producers represented that the rate increases and other economic incentives provided were sufficient to stimulate the necessary gas exploration and development.

It is crystal clear, however, that the producers did not and will not commit gas to the interstate market at price set by the Commission when they see the opportunity of obtaining a higher price.

Dr. Paul Davidson of Rutgers University describes the phenomenon as follows:

> For any particular producer, gas in the ground is a stock or inventory. The more used today, ceteris paribus, the less there will be available to sell tomorrow. Consequently, the individual producer is faced with the problem of deciding whether to enter into a long-term contract to sell his entire inventory at a series of future dates at a price specified today (including escalation) -- or to hold off his goods until some time in the future. There is an incentive to delay if the costs as far as the producer is concerned, is the opportunity cost of entering into a contract which sacrifices the present value of expected marginal profits which he gives up by selling some gas today and at future dates before an expected increase in the wellhead price. (12 R. 1387)

He further pointed out:

> In the current situation an individual producer with a lease on a field which is yet in an early stage of development, must decide either to commit large sums to develop his field -- to "prove reserves"--in order to sell the gas at some early future time, or to speculate on the underground inventory that the price will rise sufficiently to offset the costs of holding the gas a little longer in its undeveloped stage. Moreover, he can minimize carrying costs by keeping the reserves in as low a stage of development as possible. Thus, the opportunity cost of waiting for the F.P.C. to increase ceiling prices tomorrow is merely the carrying costs, which can often be limited to the lease acquisition outlays. Offsetting these carrying costs for the producer is the anticipation of the present value of the bonanza of selling gas for 20 years at several cents more per Mcf.

Former FPC economist, George Donkin, in a paper given at the British Columbia Energy Conference in June 1974, argues convincingly that the FPC's policies and actions to provide greater incentives for natural gas production, and to attract gas away from the unregulated intrastate markets "have been disappointing." Donkin cites three major factors contributing to the FPC's regulatory failure:

> (1) The FPC's regulatory innovations were premised upon the assumption that the petroleum industry would respond to price incentives in a conventional competitive manner. That is, it was implicitly assumed that if production was insufficient, prices were not high enough to cover costs plus a fair rate of return. Available evidence suggests, however, that the petroleum industry may not be workably competitive and therefore the market equilibrium price may be well above the competitive level.
>
> (2) Unregulated intrastate markets, which the FPC has used as a guide in setting interstate prices appear to be firmly administered by the petroleum producers. Therefore each time the interstate price was raised, intrastate prices were set still another notch higher thereby laying the foundation for another interstate increase, and so on ad infinitum (or so it seems).
>
> (3) While the FPC was raising prices, it was also encouraging interstate gas pipelines to expand their production interests. This served to further undermine the new price policies which were based on the assumption of competitive arms-length bargaining by independent buyers who were disinterested in profit levels in the producing sector.

In testimony presented on July 14, 1975 before the House Subcommittee on Oversight and Investigations, former FPC Chairman John Nassikas included the following table. This table clearly indicates that the FPC's policy of allowing higher prices than those allowed under either the area rate or national ceilings provided producers with a means for avoiding long-term commitments of gas to the interstate market.

Prepared by: Analysis & Compliance Division
Bureau of Natural Gas

TABLE 5

NATURAL GAS SALES COMMITTED TO THE INTERSTATE MARKET, 1971 - 1975 (1st Qtr.)

	Long-Term Contracts						Limited-Term Sales 3/		Small Producer Sales 4/		Estimated Total Annual		Emergency Sales 5/ 9/			
	National Rate Ceiling		Area Rate Ceilings 1/		Optional Procedures 2/								60-Day Sales		[illegible]-Day Sales	
	Deliveries 6/ (000,000 Mcf)	Av. Price 7/ (¢/Mcf)	Deliveries 6/ (000,000 Mcf)	Av. Price 7/ (¢/Mcf)	Deliveries 6/ (000,000 Mcf)	Av. Price 7/ (¢/Mcf)	Deliveries (000,000 Mcf)	Av. Price 7/ (¢/Mcf)	Deliveries 6/ (000,000 Mcf)	Av. Price 7/ (¢/Mcf)	Deliveries (000,000 Mcf)	Av. Price (¢/Mcf)	Deliveries 8/ (000,000 Mcf)	Av. Price 7/ (¢/Mcf)	Deliveries 8/ (000,000 Mcf)	Av. Price 7/ (¢/Mcf)
1971- 1st Qtr.	-	-	37	22.79	-	-	-	-	-	-	37	22.79	79	31.74	-	-
2nd Qtr.	-	-	65	21.77	-	-	41	33.46	-	-	106	26.29	39	34.08	-	-
3rd Qtr.	-	-	132	22.51	-	-	104	32.83	-	-	236	27.06	36	34.33	-	-
4th Qtr.	-	-	172	24.21	-	-	61	34.97	-	-	233	27.03	18	33.05	-	-
Total	-	-	406	[illegible]	-	-	205	[illegible]	-	-	612	27.14	172	[illegible]	-	-
1972- 1st Qtr.	-	-	117	24.29	-	-	50	34.23	22	25.99	189	27.11	19	35.36	-	-
2nd Qtr.	-	-	295	24.61	-	-	51	34.89	87	29.06	433	26.71	28	34.65	-	-
3rd Qtr.	-	-	66	24.59	-	-	138	33.30	63	34.02	267	31.42	24	34.78	-	-
4th Qtr.	-	-	49	24.03	1	26.50	121	35.59	58	38.67	229	33.86	17	32.58	-	-
Total	-	-	527	[illegible]	1	26.50	360	34.39	230	[illegible]	1118	29.36	88	[illegible]	-	-
1973- 1st Qtr.	-	-	124	23.38	-	-	113	37.07	36	41.07	273	31.38	35	41.34	-	-
2nd Qtr.	-	-	71	25.18	36	45.00	74	40.99	37	42.29	218	36.72	36	47.97	-	-
3rd Qtr.	-	-	50	25.68	42	35.00	76	41.76	53	45.67	221	37.77	45	48.34	21	50.66
4th Qtr.	-	-	21	27.46	9	40.42	77	45.83	55	48.79	162	44.15	-	-	87	53.77
Total	-	-	266	24.63	87	39.53	340	40.85	181	45.01	874	36.68	116	46.11	108	[illegible]
1974- 1st Qtr.	-	-	25	24.52	29	41.77	53	41.21	38	51.54	145	41.15	-	-	88	61.85
2nd Qtr.	40	26.78	22	26.78	-	-	41	42.73	42	51.07	145	38.33	16	58.84	-	-
3rd Qtr.	177	51.55	-	-	13	45.00	-	-	42	57.47	232	52.25	11	74.77	-	-
4th Qtr.	51	49.07	1	25.41	12	45.00	13	56.00	32	55.70	109	57.54	38	79.26	-	-
Total	[illegible]	[illegible]	[illegible]	[illegible]	54	43.87	107	[illegible]	154	[illegible]	631	[illegible]	65	[illegible]	88	61.85
1975- 1st Qtr.	194	52.31	6	24.72	-	-	1	63.53	19	63.54	220	52.58	16	83.40	-	-
1971 - 1975 (1st Qtr.) Total	462	49.45	1253	24.38	142	41.10	[illegible]	37.39	[illegible]	43.20	3455	35.60	457	[illegible]	196	57.08

Note: Data are rounded and do not always add to totals shown. Volumes estimated by multiplying anticipated monthly or daily quantities by term. Actuals used where available.

1/ Area rate ceilings established in Commission Orders issued as follows: Hugoton-Anadarko (Op. 586), September 18, 1970; Appalachia (Order 411), October 2, 1970; Texas Gulf Coast (Op. 595), May 6, 1971; Rocky Mountain (Order 435), July 15, 1971; Southern Louisiana (Op. 598), July 16, 1971; Other Southwest (Op. 607), October 29, 1971; Permian Basin (Op. 662), August 7, 1973. Also includes sales in Permian Basin under paragraph 12, Docket No. R-389A, issued July 17, 1970.
2/ Order No. 455, issued August 3, 1972.
3/ Order No. 431, issued April 15, 1971.
4/ Order No. 428-C, issued April 10, 1972.
5/ Order No. 418 (60-day sales) issued December 10, 1970.
6/ Anticipated annual sales volumes.
7/ Initial prices weighted by anticipated annual sales volumes (or by total deliveries during period of emergency sales).
8/ Anticipated deliveries during indicated period.
9/ The procedures for emergency and limited term sales were discontinued on June 21, 1974, by Opinion No. 699 and reinstated on September 9, 1974, by Opinion No. [illegible].

Finally, to round out the Nassikas Commission's record of undermining "just and reasonable" regulation, Chairman John Dingell of the House Subcommittee on Energy and Power revealed on January 14, 1975 that his

> Subcommittee's investigation and hearings have already disclosed, on the basis of documents filed in the FPC. that gas producers were not delivering the volumes of gas required under their certificates and their contracts with the interstate pipelines. The contract violations were discovered by the FPC in 1961 when gas curtailments first began to appear. FPC officials admitted in the hearings that the FPC has adequate power to enforce these delivery requirements, but that they failed to do so. After four years of nonenforcement, the FPC announced, on October 14, 1975--only 16 days before the start of this winter's heating season -- that it would begin to enforce these requirements.
>
> ****
>
> We also know that during 1975, the FPC conducted investigations intended to accelerate gas production in order to alleviate the projected gas shortage this winter. However, testimony before the Subcommittee has indicated that these investigations were doomed to failure from the beginning. We were told that former Chairman Nassikas deliberately denied funds to obtain a critically needed expert consultant, and thus effectively undermined the investigation. Amazingly, two days after our October 24 hearing, funds were suddenly discovered for the consultant.
>
> It seems quite clear that the FPC has bungled the Transco investigation from the beginning. After six months of investigation, the FPC says it asked the producers for the wrong documents.

The Energy & Power Subcommittee also learned that Frank Allen, Chief of the Bureau of Natural Gas, unilaterely changed the findings of his staff's study, which recommended a national area rate of 61 cents per Mcf, and forwarded to the Commission his own recommendation of a price range of 85¢ - $1.50.

Noting all of the FPC's failures, Chairman Dingell concluded, "one of the major reasons that regulation has not been effective and that we may be facing gas shortages is that the Administration, top FPC officials and the Commission itself have been so strongly committed to deregulation." (emphasis added)

TABLE 1
LOWER 48 STATES
NET RESERVE ADDITIONS
INTERSTATE VS. INTRASTATE

	Total Net AGA Reserve Additions	Net Interstate Reserve Additions (Form 15)		Inferred Intrastate Reserve Additions 1/	
Year	Tcf	Tcf	Percent	Tcf	Percent
1964	20.1	10.6	53	9.5	47
1965	21.2	13.3	63	7.9	37
1966	19.2	14.2	74	5.0	26
1967	21.1	14.8	70	6.3	30
1968	12.0	9.5	79	2.5	21
1969	8.3	6.1	73	2.2	27
1970	11.1	0.0	0	11.1	100
1971	9.4	2.0	21	7.4	79
1972	9.4	(0.2)	0	9.6	100
1973	6.5	1.1	17	5.4	83

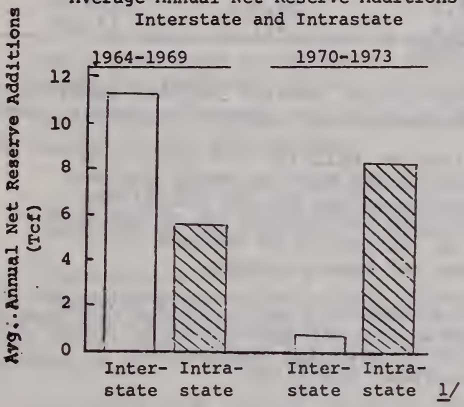
1/ Derived by assuming that intrastate reserve additions are equal to the difference between total AGA reserve additions and the reserve additions committed to the interstate market.

Whereas in 1969, 73 percent of all Net Reserve Additions of natural gas were committed to the interstate market, the following year this percentage dropped all the way to 0. The figures for 1970-73 provide proof that the intrastate market absorbed 92 percent of the total net reserve additions for the period 1970 through 1973, with the interstate market receiving only eight percent of the new reserves.

BNG noted this wide disparity in fortunes of the intrastate and interstate markets over the 1974-73 decade:

It would seem from the information shown on Table 1 that the intrastate market has had net reserve additions averaging 8.4 Tcf per year for the four years 1970-73 as compared with an average of 5.6 Tcf per year for the prior six year period 1964-69. This is in sharp contrast to the recent reserve addition experience for interstate supply where average annual net reserve additions for the 1970-73 period were only about 0.7 Tcf as compared with approximately 11.4 Tcf for the 1964-69 period. The disparity between the recent net reserve addition records of the two gas industry components is also shown on Figure 11.

Figure 11
Average Annual Net Reserve Additions
Interstate and Intrastate



On the basis of this data, the Commission's Bureau of Natural Gas was forced to conclude that "...to a degree, the recent relative advantage of the intrastate has been at the expense of interstate supply."

During hearings before the Committee on Commerce of the United States Senate on the Consumer Energy Act of 1974, Senator James Buckley presented figures which show that, at least in the Permian Basin, the injury to the gas supply of the interstate market caused by the intrastate market commenced as early as 1968:

GAS COMMITMENTS IN THE PERMIAN BASIN 1966-70

Year	Percent Committed To Intrastate Market	Percent Committed To Interstate Market	Total Commitment (billion cubic feet
1966	16.3	83.7	178.0
1967	21.8	78.2	77.2
1968	87.2	12.8	156.1
1969	83.2	16.7	175.8
1970(6 mo)	90.9	9.1	113.4

SOURCE: From FPC data.

On the basis of the table, Senator Buckley observed during the October 10, 1973 Hearing of the Senate Consumers Committee:

> What [the] figures tell is that while, in 1966, 83.7 percent of new Permian Basin gas was sold in interstate pipelines by the end of the first 6 months of 1970 the proportion of new gas being committed to interstate as opposed to intrastate markets had been reversed.
>
> In the first 6 months of 1970, 90.9 percent of new Permian Basin gas was being sold to intrastate consumers while only 9.1 percent was connected to interstate pipelines.

During his July 14, 1975 appearance before Congress, the former Chairman noted that there were two possible solutions to the discrimination against the interstate market, i.e., regulations of both the interstate and intrastate markets or "to attempt to have competition and price regulate the flow of that gas and allocate that resource;" however, he admitted that the second alternative, i.e., deregulation, might very well not alleviate the intrastate market's injurious effect on the interstate consumers even if approved by Congress:

> The difficulty with that latter suggestion is that the price consideration is not necessarily going to allocate that resource to the other State because there is an inherent economic advantage to the State that is the producer State as to its sources.

In a 1974 appearance before the House Interstate and Foreign Commerce Committee's Special Subcommittee on Investigations, Chairman Nassikas drew the contrast between the rapidly expanding intrastate market and the resulting contraction of the interstate market:

> The intrastate market has succeeded in expanding at a very large and accelerated compound rate compared to a very static interstate market. We have stayed still, practically, on production. In fact, we peaked last year.
>
> I think it is probably safe to say we will have less gas produced this year than last but much more in the intrastate market.

The former Chairman gave a very simple explanation of the cause of this phenomenon:

> If a man could sell his gas intrastate at a price, he would not be interested in selling it interstate at a lower price.

This past summer in a hearing before a Subcommittee of the House Government Operations Committee on June 26, former Chairman Nassikas gave Congress a more in depth view of the basis of the intrastate price and why the interstate price cannot match it:

> The cost of gas today in the intrastate market does not bear a relationship to the price of that gas. The price of that gas in the intrastate market is determined by a seller's market in a time of great shortage and, second, based upon the commodity value of that gas in comparison to the world price of oil.
>
> It may be three times the price of the cost of the gas. We can't do this unless the Congress lets us do it. (Emphasis added)

THE NEED FOR REGULATION OF THE INTRASTATE MARKET

On September 25, 1975, the Chairman of the House Subcommittee on Oversight and Investigations (which has been conducting hearings into the reasons behind the so-called "natural gas shortage"), John E. Moss stated, "The current shortage of natural gas is not, as some contend, the inevitable result of Federal regulation which provides natural gas producers with a generous 15 percent rate of return on their investment. It is rather the result of two factors: the failure of Congress to extend regulation to the intrastate market and, more importantly, the result of industry speculation concerning future increases in the price of natural gas."

Because only part of the natural gas market is regulated, a great deal of gas is being diverted to the unregulated intrastate markets. The existence of such a situation allows producers to leverage supplies to get ever higher prices in the regulated interstate market. Given the fact that the natural gas industry is not competitive, it is imperative that regulation be extended to the intrastate market. Why should intrastate users be exploited more than interstate users of natural gas?

At the present time, approximately one-third to one-half of the gas consumed in the nation is consumed in unregulated intrastate markets which are, for the most part, Texas, Louisiana and Oklahoma. Prior to the 1973 OPEC price increase, intrastate prices were comparable with prices in the interstate market. This is indicated by comparing the following two charts used by former FPC economist George Donkin in a paper given in April 1974 at the British Columbia Energy Conference. The first chart shows the weighted average price of new sales contracts between large producers and intrastate buyers between September 1971 and September 1972. The second chart shows the ceiling prices set by the Federal Power Commission for the same areas. All of the area rates fall in the range of initial contract rates and closely approximate the weighted average. Moreover, as pointed out by Mr. Donkin, "the weighted average initial contract price for these sales was, in each area, less than prices being paid by interstate pipelines under emergency and limited terms sales authorized by the FPC."

CHART I

1971-72 Prices in the Intrastate Markets

FPC Pricing Area	Initial Contract Rates	
	Weighted Average Cents Per Mcf	Range Cents Per Mcf
Southern Louisiana	28.06	21.57 - 34.31
Other Southwest	34.60	17.09 - 51.96
Hugoton-Anadarko	27.09	14.08 - 40.22
Texas Gulf Coast	30.64	17.09 - 43.74
Permian Basin	30.13	14.08 - 37.20

CHART II

1970-73 Prices in the Interstate Market

Area	FPC Opinion Number and Date Issued		Ceiling Price in Cents per 1,000 Cu. Ft.	Previous Ceiling Price in Cents per 1,000 Cu. Ft.
Appalachia	411	10-02-70	24.0 - 34.0	28.0
Hugoton-Anadarko	586	09-18-70	19.0 - 20.5	12.0 - 17.0
Texas Gulf Coast	595	05-06-71	24.0	16.0 - 17.0
Southern Louisiana	598	07-16-71	26.0	17.0 - 20.0
Other Southwest	607	10-29-71	25.0 - 26.0	15.0 - 20.6
Permian Easin	622	08-07-73	35.0	14.5 - 16.5

[Note that during the period 1970-72 prices in both interstate and intrastate markets were comparable. However, subsequent to the OPEC price increase of 1973, producers have rapidly widened the gap in prices between these two markets.]

Following the OPEC price increases, however, producers in the intrastate markets rapidly began to increase their prices to approximate the monopolistically determined OPEC-level. An FPC report released December 12, 1975 showed "that the monthly weighted average price for new contracts for these intrastate sales averaged $1.259 per thousand cubic feet for the period covered--January through June 1975. These prices ranged from $1.044 per thousand cubic feet in March to $1.536 in April. Prices for renegotiated or amended contracts ranged from 76.43 cents per thousand cubic feet in March to $1.668 in April, with a 6-month average of $1.415." These prices were more than double the weighted average price for new contracts in the regulated interstate market during the same period.

By being able to outbid interstate pipelines, buyers in the intrastate markets are able to divert large amounts of gas away from consumers dependent on the interstate market. The ability of the unregulated intrastate markets to divert gas supplies from the regulated interstate market has been apparant for some time. Former FPC Chairman John Nassikas informed Congress of the injury being suffered by the interstate market and its cause as early as 1972 in testimony before the Senate Committee on Interior and Insular Affairs:

> Now, there are distortions. There are diversions of which I am very mindful, of gas from interstate markets to intrastate.....
>
> We have recognized and attempted (sic) in our docket No. 389-A, which was specifically a national investigation in rulemaking, which is still continuing, the large discrepancy between intrastste prices and interstate prices.

Despite Nassikas' recognition that the unregulated intrastate markets could divert supplies from the interstate market, the FPC's response was to suggest that interstate prices had to be raised so that interstate pipelines could compete with intrastste pipelines. But, this approach was clearly self defeating, due to the nature of the unregulated intrastate markets, which could always outbid the interstate market. Economist George Donkin noted "the futility of using price as a mechanism to divert new supplies to interstate markets."

Donkin illustrated further that,

> ...when the FPC raised the Area Rate from 16.5 centes to 35.0 cents per Mcf in 1973 in the Permian Basin, the price in any intrastate contract containing both a favored-nation provision and a contract price less than 35.0 cents was immediately increased to the higher Area Rate. As long as producers are able to obtain contract provisions linking intrastate prices to regulated interstate rates, effective Federal regulation is destined not to succeed.

In more recent testimony, former FPC Chairman Nassikas on July 14, 1975 told the House Subcommittee on Oversight and Investigations that:

> Gas supply for the interstate pipelines is deteriorating at an even faster pace largely because interstate pipelines are being outbid by intrastate buyers in competition for new gas supplies.

As a result,

> ...the intrastate market will receive the lion's share of new natural gas commitments, production will fall short of meeting the demands of the national market for gas, higher priced gas supplements and substitute fuels will increase the price paid for energy by consumers, and dislocations in energy markets will adversely impact on our economy.

The FPC's Bureau of Natural Gas revealed the magitude of this diversion of gas to the intrastate market in a December 1974 Staff Report entitled "A Realistic View of U.S. Natural Gas Supply." BNG compiled the following table showing the dramatic shift in new Net Reserve Additions of natural gas producers from the interstate to the intrastate market, which began in 1970:

The fact that the price of natural gas in the intrastate market bears no relationship to its cost is basically due to the inherent non-competitiveness of the producer market. The existence of this non-competitive "seller's market," especially in a time of a shortage of gas supplies being placed on the market, is what led the Supreme court to reaffirm the conclusion in Federal Power Commission v. Texaco in 1974, that the prevailing price in the marketplace may not be equated with the "just and reasonable" rates required by the Natural Gas Act:

> ...in our view the prevailing price in the marketplace cannot be the final measure of "just and reasonable" rates mandated by the Act. It is abundantly clear from the history of the Act and from the events that prompted its adoption that Congress considered that the natural gas industry was heavily concentrated and that monopolistic forces were distorting the market price for natural gas. Hence, the necessity for regulation and hence the statement in Sunray DX that if contract prices for gas were set at the market price, this
>
>> "would necessarily be based on a belief that the current contract prices in an area approximate closely the 'true' market price--the just and reasonable rate. Although there is doubtless some relationship, and some economists have urged that it is intimate, such a belief would contradict the basic assumption that has caused natural gas production to be subjected to regulation . . . ."
>
> In subjecting producers to regulation because of anticompetitive conditions in the industry, Congress could not have assumed that "just and reasonable" rates could conclusively be determined by reference to market price. Our holding in Phillips implies just the opposite.

This interstate price leverage of producers which own intrastate pipelines was also exposed by Dr. John Wilson in testimony he gave before the Senate Judiciary Committee's Subcommittee on Antitrust and Monopoly in June of 1973 when he was Chief of the Division of Economic Studies of the FPC's Office of Economics:

> These then are the buyers who are bidding up the intrastate price in the Permian Basin. Surely one can be forgiven for suspecting than when Pennzoil, Amoco, Coastal States, et al., acting as intrastate buyers, bid up the price of gas, there may be some potential for certain fairly obvious ulterior motives. A complete list of all the major intrastate buyers in major producing areas who were identified by the FPC in the 1972 intrastate price survey is presented in Table 18. It would be quite incredible, in view of this information, to permit these parties to go on establishing so-called intrastate "market prices" which they and their own corporate affiliates subsequently press upon the interstate market. Surely this gaping regulatory loophole must be closed if regulation is to work. The exemption presently undermines the Federal government's ability to regulate interstate commerce.

Thus, it is important to recognize that the major oil companies, who are subject to regulation when they sell gas in the interstate market, are free of regulation in the intrastate markets (where they are free to charge monopoly prices). Thus, the major producers, who completely control the intrastate price, also use that price to extract a higher interstate rate when they appear before the Federal Power Commission.

Dr. David Schwartz, who at the time of his appearance before the Senate Committee on Commerce in October 1973 was Assistant Chief of the FPC's Office of Economics, explained in his testimony one of the major ways in which the large gas producers use their ability to establish intrastate rates to raise the level of interstate rates:

> ...the major producers have extensive intrastate pipeline systems (e.g., Continental Oil, Exxon, Texaco, Atlantic Richfield, and Amoco all have major intrastate gas pipeline networks) and in this capacity they are purchasers of natural gas. It is obvious that they can use this leverage to pay higher prices for gas on the intrastate level as justification for the price they should receive as sellers of gas in the interstate market. This dual role of buyer-seller by the major petroleum companies completely undermines any prospect of rivalry fundmental to the assumption of a workably competitive market. In light of the absence of independence between buyers and sellers and the pervasive system of joint ventures and corporate interties between sellers, it defies credulity for any one to assume effective competition in the natural gas producing industry.

TABLE 18.—INTRASTATE BUYERS IDENTIFIED IN THE 1972 FPC SURVEY OF INTRASTATE NATURAL GAS PRICES

(Docket R389A)

Area and intrastate buyer	Also a gas producer?[1]	Interstate pipelines served in 1971[1]
PERMIAN BASIN		
1. Pecos Growers Oil Co.	Yes	Lone Star Gas Co., Natural Gas Pipeline Co., El Paso Natural Gas Co., Arkansas Louisiana Gas Co., Cities Service Gas Co., Colorado Interstate, Florida Gas Trans. Co., Michigan Wisconsin Pipeline Co., Northern Natural Gas Co., South Texas Natural Gas Gathering Co., Tennessee Gas Pipeline, Texas Eastern Trans. Corp., Trunkline Gas Co., Transcontinental Gas P.L., United Gas Pipeline Co.
2. Pecos Growers Gas Co	Yes	See Pecos Growers Oil Co above.
3. Delhi Gas Pipeline Corp	Yes	Do.
4. Intratex Gas Co.	Yes	Consolidated Gas Supply Corp., Natural Gas P.L. Co., South Texas Nat. Gas Gath., Texas Eastern Trans. Corp., Texas Gas Pipe Line, Transcontinental Gas Pipeline Corp., Valley Gas Trans. Inc.
5. Houston Pipeline Co.	Yes	See Intratex Gas Co. above.
6. Dow Chemical Co.	Yes	None in 1971.
7. Lo-Vaca Gathering Co.	Yes	Cities Service Gas, Columbia Gas Trans., Consolidated Gas Sup., Lone Star Gas Co., Natural Gas P. L. Co. South Texas Natural Gas Gathering Co., Tennessee Gas Pipeline, Texas Eastern Trans., Transcontinental Gas Pipeline Corp., Trunkline Gas Co. Arkansas Louisiana Gas, El Paso Natural Gas Co., Northern Natural Gas Co., Colorado Interstate Gas, Florida Gas Trans. Co.
8. Texas Utilities Fuel Co	Yes	None in 1971.
9. BTA Oil Producers	Yes	El Paso Natural Gas Co.
10. Lone Star Gas Co.	Yes	Arkansas Louisiana Gas, Lone Star Gas Co., Natural Gas P.L. Co., Panhandle Eastern P. L., Texas Eastern Trans, Transcontinental Gas Pipeline Corp., United Gas P. L. Co.
11. Pioneer Natural Gas Co.	Yes	Michigan Wisconsin P.L., Natural Gas P. L. Co., Northern Natural Gas Co., Panhandle Eastern P. L.
12. Pennzoil Pipeline Co.	Yes	United Gas Pipeline Co., Arkansas Louisiana Gas Michigan Wisconsin P. L., Natural Gas P. L. Co., Sea Robin P. L. Co., South Texas Natural Gas Gathering Co., Southern Natural Gas Co., Tennessee Gas Pipeline, Texas Eastern Trans., Texas Gas Trans. Corp., Transcontinental Gas Pipeline Corp., Trunkline Gas Co., United Gas Pipeline Co., Columbia Gas Trans., Consolidated Gas Sup., Transwestern P. L. Co.
13. Amoco Gas Co.	Yes	Arkansas Louisiana Gas Co. Cimarron Trans. Co., Cities Service Gas Co., Colorado Interstate Gas, Columbia Gas Trans., El Paso Natural Gas Co., Florida Gas Trans. Co., Lone Star Gas Co., Michigan Wis. P. L. Co., Miss. River Trans. Corp., Montana Dakota Utility Co., Mountain Fuel Sup. Co., Natural Gas P. L. Co. Northern Natural Gas Co., Northern Utilities Co., Panhandle Eastern P. L., Sea Robin P. L. Co., Southern Nat. Gas Co. Tennessee Gas Pipeline. Texas Eastern Trans. Corp., Texas Gas P. L. Corp., Texas Gas Trans. Corp., Transcontinental Gas P. L., Transwestern P. L. Co., Trunkline Gas Co., United Gas P. L. Co., Valley Gas Trans., Inc.
14. Llano, Inc.	No	N/A.
TEXAS GULF COAST		
1. Amoca Gas Co.	Yes	See Amoco Gas—Permian Basin
2. Atlantic Richfield Co.	Yes	Arkansas Louisiana Gas Co., Cimarron Trans. Co., Cities Service Gas Co., Colorado Interstate Gas Co., Columbia Gas Trans. Corp., El Paso Natural Gas Co., Florida Gas Trans. Co., Kansas Nebraska Natural Gas Co., Lone Star Gas Co., Michigan Wisconsin Pipeline, Montana Dakota Utility Co., Mountain Fuel Supply Co., Natural Gas P. L. Co., Northern Natural Gas Co., Northern Utilities Co., Panhandle Eastern P. L. Co. South Texas Natural Gas Gathering Co., Southern Natural Gas Co., Tennessee Gas Pipeline, Texas Eastern Trans. Corp., Texas Gas Trans. Corp., Transcontinental Gas P. L. Co., Transwestern P. L. Co., Trunkline Gas Co., United Gas P. L. Co., West Texas Gath. Co.
3. Channel Industries Gas Co.	Yes	Arkansas Louisiana Gas Co., Cimarron Trans. Co., Cities Service Gas Co., Columbia Gas Trans. Corp., El Paso Natural Gas Co., Florida Gas Trans. Co., Michigan Wisconsin P. L. Co., Mississippi River Trans. Corp., Montana Dakota Utility Co., Mountain Fuel Supply Co., Natural Gas P. L. Co., Northern Natural Gas Co., Oklahoma Natural Gas Gathering Corp., Panhandle Eastern P. L. Co., South Texas Natural Gas Gathering Co., Southern Natural Gas Co. Tennessee Gas Pipeline, Texas Eastern Trans. Corp., Texas Gas Trans Corp Transcontinental Gas P. L., Trunkline Gas Co., United Gas Pipeline Co., Western Trans. Corp., Kansas Nebraska Nat. Gas Co
4. Coastal States Producing Co.	Yes	See Lo-Vaca Gathering Co.—Permian Basin.
5. Texas Gas Utilities Co.	Yes	Do.
6. Texas Southeastern Gas Co.	Yes	Do.
7. Lo-Vaca Gathering Co.	Yes	Do.
8. Continental Oil Co.	Yes	Arkansas Louisiana Gas Co., Cascade Natural Gas Corp., Cities Service Gas Co., Colorado Interstate Gas Co., El Paso Natural Gas Co., Florida Gas Trans. Co., Kansas Nebraska Natural Gas Co., Lone Star Gas Co., Michigan Wisconsin P. L. Co., Montana Dakota Utility Co., Mountain Fuel Supply Co., Natural Gas P. L. Co, Northern Natural Gas Co., Northern Utilities Co., Panhandle Eastern P. L. Co., South Texas Natural Gas Gathering Co, Southern Natural Gas Co, Tennessee Gas Pipeline, Texas Eastern Trans. Corp., Texas Gas Trans. Corp., Transcontinental Gas P. L., Transwestern P. L. Co., Trunkline Gas Co., United Gas P. L. Co., West Texas Gathering Co.
9. Delhi Gas Pipeline Corp.	Yes	See Delhi Gas Pipeline Corp.—Permian Basin.
10. Dow Chemical Co.	Yes	None in 1971.
11. Houston Pipeline Co.	Yes	See Intratex Gas Co—Permian Basin.
12. Lone Star Gas Co.	Yes	See Lone Star Gas Co.—Permian Basin.
13. Pennzoil Pipeline Co.	Yes	See Pennzoil Pipeline Co.—Permian Basin.
14. Phillips Petroleum Co.	Yes	Arkansas Louisiana Gas Co., Cities Service Gas Co. Columbia Gas Trans Corp. Delta Gas, Inc. El Paso Natural Gas Co. Florida Gas Trans. Co. The Jupiter Corp. Lone Star Gas Co. Louisiana Nevada Transit, Michigan Wisconsin P. L. Co. Mississippi River Trans. Corp. Natural Gas P. L. Co. Northern Natural Gas Co. Panhandle Eastern P. L. Co., Southern Natural Gas Co., Tennessee Gas Pipeline, Texas Eastern Trans. Corp., Texas Gas Trans. Corp. Transcontinental Gas P. L. Corp., Transwestern Pipeline Co., Trunkline Gas Co., United Gas Pipeline Co., Valley Gas Trans., Inc., Western Gas Interstate Co.
15. American Smelting & Refining Co.	No	N/A.
16. Goodyear Tire & Rubber Co.	No	N/A.
17. Houston Chemical Co.	No	N/A.
18. Olin Corp.	No	N/A.

TABLE 18.—INTRASTATE BUYERS IDENTIFIED IN THE 1972 FPC SURVEY OF INTRASTATE NATURAL GAS PRICES

(Docket R389A)—Continued

Area and intrastate buyer	Also a gas producer? [1]	Interstate pipelines served in 1971 [1]
SOUTH LOUISIANA		
1. Continental Oil Co	Yes	See Continental Oil Co.—Texas Gulf Coast.
2. Allied Chemical Corp	Yes	El Paso Natural Gas Co., Lone Star Gas Co., Natural Gas Pipeline Co. Northern Natural Gas Co., Oklahoma Natural Gas Gathering Corp., Panhandle Eastern P. L. Co., Southern Natural Gas Co., Texas Eastern Trans. Corp., Texas Gas Pipeline Corp., Texas Gas Trans. Corp., Transcontinental Gas P. L. Corp., Transwestern Pipeline Co., United Gas Pipeline Co.
3. Monterey Pipeline Co	Yes	Arkansas Louisiana Gas Co., Colorado Interstate Gas Co., Columbia Gas Trans. Corp., El Paso Natural Gas Co., Florida Gas Trans. Co., Kansas-Nebraska Natural Gas Co., Lone Star Gas Co., Louisiana Nevada Transit, Michigan Wisconsin P. L. Co., Montana Dakota Utilities Co., Mountain Fuel Supply Co., Natural Gas P. L. Co., Northern Natural Gas Co., Panhandle Eastern P. L. Co., Plaquemines Oil & Gas Co., Southern Natural Gas Co., Tennessee Gas Pipeline, Texas Eastern Trans. Corp., Texas Gas Trans. Corp., Transcontinental Gas P. L. Corp., Transwestern P. L. Co., Trunkline Gas Co., United Gas P. L. Co., West Texas Gathering Co., Western Gas Interstate Co.
4. Louisiana Intrastate Gas Corp	No	N/A.
OTHER SOUTHWEST		
1. Arkansas Western Gas Co	Yes	None in 1971.
2. Arkansas Louisiana Gas Co	Yes	Arkansas Louisiana Gas Co., Arkansas Okla. Gas Corp., Mississippi River Trans. Corp., Texas Gas Trans. Corp.
3. Western Gas Corp	Yes	Kansas-Nebraska Natural Gas Co., Cities Service Gas Co., Texas Eastern Trans. Corp.
4. Delhi Gas Pipeline Corp	Yes	See Delhi Gas Pipeline Corp.—Permian Basin.
5. Bi Stone Fuel Co	Yes	None in 1971.
6. Lone Star Gas Co	Yes	See Lone Star Gas Co.—Permian Basin.
7. Oklahoma Natural Gas Co	Yes	Arkansas Louisiana Gas Co., Cities Service Gas Co., Michigan Wisconsin P. L. Co., Natural Gas P. L. Co., Northern Natural Gas Co., Oklabome Natural Gas Gathering Corp., Panhandle Eastern P. L. Co., Transwestern Pipeline Co.
8. Oklahoma Natural Gas Storage Co.	Yes	See Oklahoma Natural Gas Co. above.
9. Pioneer Natural Gas Co	Yes	Michigan Wisconsin P.L. Co., Natural Gas P.L. Co., Northern Natural Gas Co., Panhandle Eastern P.L. Co., Transwestern Pipeline Co.
10. Kansas-Nebraska Natural Gas Co., Inc.	Yes	See Western Gas Corp.—Other southwest.
11. Anadarko Prod. Co	Yes	Arkansas Louisiana Gas Co., Cities Service Gas Co., Colorado Interstate Gas Co., Kansas-Nebraska Natural Gas Co., Lone Star Gas Co., Michigan Wisconsin P.L. Co., Natural Gas P.L. Co., Northern Natural Gas Co., Panhandle Eastern P.L. Co., Texas Gas Transmission Corp., United Gas Pipeline Co., Panhandle Producing Co., Colorado Interstate Gas Co.
12. Phillips Petroleum Co	Yes	See Phillips Petroleum Co.—Texas Gulf Coast.
13. Southwestern Gas P.L	No	N/A.
14. The LBA Co., Inc	No	N/A.
15. Coastal Chemical Corp	No	N/A.
16. Oklahoma Gas & Electric Co	No	N/A.
17. Transok Pipeline Co	No	N/A.
18. Reynolds Metals Co	No	N/A.
19. Mississippi Chemical Corp	No	N/A.
20. Mississippi Power & Light Co	No	N/A.
ROCKY MOUNTAIN		
1. Amoco Gas Co	Yes	See Amoco Gas Co.—Permian Basin.
2. Colorado Interstate Gas Co	Yes	See Lo-Vaca Gathering Co.—Permian Basin.
3. Koch Industries, Inc	Yes	Arkansas Louisiana Gas Co., El Paso Natural Gas Co.
4. Koch Oil Co	Yes	See Koch Industries above.
5. McCulloch Gas Processing Corp.	Yes	McCulloch Interstate Gas Corp., Montana Dakota Utilities Co.
6. Mountain Fuel Supply Co	Yes	None in 1971.
7. Southern Union Gas Co	Yes	El Paso Natural Gas Co.
8. Cody Gas Co	No	N/A.
9. Texas Gas Corp	No	N/A.
10. Thomas G. Vessels	No	N/A.

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[1] Either the company named or an affiliate.

In his paper on competition in the natural gas industry given in April 1974 at the British Columbia Energy Conference, former FPC economist George Donkin provided some examples from FPC cases of how producers who sell gas in the interstate market are able to put pressure on the Commission for higher prices based on their position as buyers in the unregulated intrastate market.

> Recently, the FPC approved a price of 55 cents per Mcf for a group of producers selling interstate gas to the Southern Natural Gas Company in Alabama. One of the producers in this proceeding is the St. Regis Paper Company, which owns oil and gas properties in Southern Alabama and the Florida Panhandle. Much of the evidence presented by the producers and Southern Natural in this proceeding related to intrastate prices and a Chevron Oil Company (Standard Oil of California) intrastate contract containing a price of 56 cents per Mcf was made part of the official hearing record. The purchaser of this 56-cent gas is none other than the St. Regis Paper Company, one of the producers basing a request for higher interstate prices in the same proceeding on enhanced prices in intrastate markets.

In addition to the data collected by the FPC on intrastate sales, in 1973 the Monterey Pipeline Company (a wholly owned subsidiary of Exxon) published data on the industrial customers served by intrastate pipelines in Louisiana, including total estimated 1973 gas sales to these customers. These data are summarized in Table 4.

Table 4

Major Intrastate Pipelines Serving Industrial Customers in Louisiana 1973

Pipeline/(Affiliation)	Col. (1) Estimated Industrial Sales 1973 (1000 Mcf)	Col. (2) Col. (1) As Percent Of Total (%)
Texaco (Texaco)	554,800	43.4
United Gas P. L. (Pennzoil)	187,975	14.7
Monterey (Exxon)	148,555	11.6
Louisiana Intrastate	78,475	6.1
Sugar Bowl Gas Corp. (Union Texas Petr.)	75,190	5.9
Continental (Continental Oil)	67,525	5.3
Ark. La. Gas Co. (Arkla Explor. Co.)	34,310	2.7
Creole Gas P. L. Corp.	23,725	1.8
La. Gas Purchasing Co.	12,775	1.0
La. Gas Prod. Co. (La. Gas Prod. Co.)	12,045	.9
Shell (Shell Oil Co.)	10,950	.9
Cities Service Co. (Cities Svc. Oil Co.)	10,220	.8
Crown Zellerbach	10,220	.8
Miscellaneous	52,560	4.1
Totals	1,279,325	100.0

Source: Monterey Pipeline Company, Map of State of Louisiana Industrial Plant Gas Consumers, February, 1973.

As in the case of the FPC data, Monterey's figures show that gas pruchasers in intrastate markets are often corporate affiliates of natural gas producing companies. In 1973, producer affiliates operated the pipelines which accounted for 86.9 percent of the total natural gas resold to industrial consumers within Louisiana. Affiliates of Texaco, Continental Oil, Exxon, Pennzoil and Union Texas Petroleum -- each of which are major producers and sellers of natural gas to interstate pipelines -- accounted for nearly 81 percent of total Louisiana industrial sales. Moreover, many of these sales were actually internal transactions between affiliated buyers and sellers or sales to other petroleum companies. To illustrate, 46.7 percent of Monterey's total industrial sales were to its parent, Exxon, and an additional 7.3 percent were made to Shell, Mobil, and Allied Chemical. The Shell pipeline delivered 100 percent of its industrial use gas to subsidiaries of its parent, Shell Oil, while the Continental pipeline delivered 27.2 percent of its total indistrial sales to Continental Oil Company. Fianlly, of the 554.8 billion cubic feet (Bcf) of gas sold through Texaco's intrastate system, 317 percent was sold to several corporate affiliates of natural gas producing companies.

The potential of intrastate pipelines -- specifically Monterey, Sugar Bowl (Allied Chemical) and Continental -- to exert upward pressure upon regulated prices became manifest once again in another recent producer rate case. There, the Louisiana Land and Exploration Company requested a price of 50.0 cents per Mcf under a new contract with Texas Eastern Transmission Corporation. The producers attempted to justify the higher rate by referring to offers in the same area of 50.0 cents or more by Monterey, Sugas Bowl and Louisiana Intrastate. An executive of Texas Eastern stated that in 1972, Texas Eastern offered 47 cents for new gas reserves in Louisiana but was out-bid by Continental Oil's intrastate pipeline and that Continental was currently purchasing gas in Louisiana at 50.0 cents per Mcf.

In denying this 50-cent rate, the FPC did not address the intrastate price issue. Rather, it held that since the sale was to be from wells in fields dedicated to Texas Eastern under an

> earlier contract, Louisiana Land was not eligible to collect rates above the 26-cent price contained in that contract. Since Texas Eastern, the buyer, is (1) actively engaged in oil and gas production through its subsidiaries, Texas Eastern Exploration Company and La Gloria Oil and Gas, and (2) through these subsidiaries, a joint venture partner of Louisiana Land, the FPC staff maintained that in view of the fact that Texas Eastern already had a valid and binding contract at 26 cents, its willingness to agree to the 50-cents price could not be construed as reflective of competitive "arm's length" negotiations between independent buyers and sellers.

Since the exorbitant price of the non-competitive marketplace does continue to exist in the unregulated intrastate market, the intrastate market is receiving far more than its fair share of the nation's natural gas supply at the expense of interstate commerce, as pointed out by former Chairman Nassikas on June of 1975:

> Forty percent of our gas is in an unregulated intrastate market, where the gas is being sold for double to three times the price that we can set for natural gas under the Natural Gas Act.

But the former Chairman steadfastly maintained before Congress that even though the intrastate market is receiving an overflowing supply of natural gas while high priority interstate consumers are experiencing ever deepening curtailment, "We do not have the power to divert gas from an intrastate pipeline or distributor to an interstate use. . . ."

Nassikas admitted that the regulated interstate rate may not be lawfully set at the unregulated intrastate price because the latter is not cost based, and therefore to set the interstate price at the intrastate level would be tantamount to deregulation of the interstate rate. But since the former Chairman and the other Commissioners also believe that the Commission has no power to bring intrastate prices down to a level which removes the competitive disadvantage of the interstate market or to allocate gas between the two markets, Nassikas maintained before the Senate Commerce Committee on February 19, 1974 that the FPC must just sit back and permit the gas to be siphoned off by the intrastate market:

> We are charged by the Congress and the Natural Gas Act to regulate. We are not regulating if we are compelled to accept a price offered by a producer in competition with the intrastate market--which cannot be sustained by evidence of costs approved by the Commission or, in the absence of a rational basis for acceptance including unit costs of the project in addition to relevant economic factors.
>
> If the unregulated intrastate market or producer-stimulated prices in excess of a workably competitive market control the price level to consumers in the interstate market above the level reasonable justified by costs, including a reasonable return, producers will receive windfall profits sanctified by orders of this Commission.
>
> I cannot endorse this kind of nonregulation and I am certain that my colleagues cannot either. It is not our mission to enable producers to be unjustly enriched at the expense of interstate consumers, even if our failure to certificate a sale may result in less gas for the interstate market.

Additional evidence as to how major oil companies have been able to use their ability to purchase gas in the unregulated intrastate market to cause injury to the interstate market was presented by members of the staff of the Federal Power Commission to the House Subcommittee on Energy and Power on January 15, 1975.

The hearings chaired by John Dingell revealed that substantial quantities of natural gas produced from the offshore federal domain, gas which should only be sold in interstate commerce, has been diverted by a number of major companies to their own facilities and/or industrial customers in the intrastate markets. These diversions, according to Chairman Dingell were both legal and illegal. In the hearings, it was brought out that:

(1) One offshore producer was allowed to sell interstate gas illegally to an intrastate pipeline for ten years without being discovered.

(2) One trillion cubic feet of offshore natural gas, supposedly reserved for the interstate pipeline system, has been and is being diverted by major gas producers for their own use in refineries, chemical plants, etc.

In one case involving the Tennessee Gas Pipeline, Tenneco Oil Company (both companies are subsidiaries of Tenneco, Inc.) was shipping interstate gas on the pipeline and the pipeline was delivering the gas to an intrastate pipeline. According to the FPC staff, over a six year period, approximately 18.6 billion cubic feet of interstate gas was delivered to an intrastate industrial user as well as to Tenneco's own refinery. During this period Tennessee Gas Pipeline was curtailing its interstate industrial customers. The FPC is still allowing this practice to continue.

The second case involves the disposition of a certain percentage of gas from a producer's offshore federal acreage for his own use. Up until 1969, that is, before the advent of the Nassikas Commission, in most of the contracts that were filed with the Commission all the reserves underlying specified leases were dedicated to interstate commerce. According to the January 15 testimony of FPC attorney, George Lewnes,

> Subsequent to 1969 and becoming increasingly prevalent in the past two years, we have had producer applications filed seeking to sell gas to the pipeline with reservations, and the reservations could be a percentage reservation of the production; that is, the producer reserves a right to own as much as 50 percent of the gas and seeks to have that gas transported for his own account by the pipeline.

Lewnes described a specific situation in which the Mobil Oil Company reserved 50 percent of gas from one of its leases for its own use in the intrastate market. In this case the Commission staff in 1972 opposed the decision to grant this reservation to Mobil on the grounds that "Mobil volumes of gas would be diverted to unknown and unspecified present and future uses." The Commission, however, approved the proposal.

The FPC staff also revealed that a number of companies, including the Gulf Oil Corporation, have built pipelines out into the federal offshore domain, which deliver gas for the producer's own use in the intrastate market. In many cases, this use will either be a refinery or a chemical plant (a fertilizer plant, an ammonia plant, for example). Thus, this producer would be able to displace high-priced intrastate gas with lower-priced interstate gas.

In a similar case, Mobil, which has just contracted to sell intrastate gas at $1.90 Mcf to some out of state industrial customers, is supplying its oil refinery in Beaumont, Texas (which once consumed the gas now shipped to the out of state industrial customers) with reserved gas from one of its federal offshore fields. In the case of Mobil, the arrangement at present is within the law.

Finally, it was brought out that approximately one trillion cubic feet of offshore federal domain gas, which should be dedicated to interstate commerce, is being reserved by major producers. In just one case some 280,000 Mcf/day are being reserved. Some of the companies and their reservations of gas include:

Shell-----------------22,500 Mcf/day

Tenneco---------------37,500

Continental-----------25,000

Transocean------------38,500

Ashland, et.al.-------43,500

Placid, et.al.--------43,500

With the above documentation, it is obvious why there is a shortage in the interstate market. With major oil companies able to manipulate supplies by increasing deliveries of interstate gas into the intrastate markets and with the FPC allowing this situation to exist, it is no wonder why industrial users hooked up to the interstate system are being deprived of supplies and being threatened with plant shutdowns.

Commenting on the evidence presented before the Subcommittee, Rep. William Broadhead observed:

> It seems clear to me that the Commissioners and some of the top executives of the Federal Power Commission are taking very much of an inconsistant position. On the one hand, they come before us and they tell us that there is going to be a very severe gas shortage this winter, that it is an emergency and we must do something about it. Of course, this situation that they say is dire and we must move quickly and we must deregulate. But yet when evidence is presented to the Commission that gas is available that ought to be available for the interstate market, it is not going into that market, the Commission does little or nothing about it.
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> * * * *
>
> Literally billions and billions of Mcf of gas that ought to have gone into interstate market was illegally and fraudulently diverted from that market and with no effective action by the Commission to do anything about it.

Because of the lack of competition in the natural gas producing market, because of the producers' ability to divert gas from the interstate market to the intrastate market, because of the producers' ability to always force the price the price of intrastate gas to a higher level than in the interstate market, and because of the FPC's reluctance to regulate salesof gas in the intrastate market, interstate consumers have been and are being seriously discriminated against. Commenting on this serious discriminatory situation, former FPC Assistant Chief economist, Dr. David Schwartz concluded in October 1973 hearings before the Senate Commerce Committee:

> In order for regulation to succeed at the interstate level, it is critical that regulation be extended to the entire market....These spiralling intrastate price increases are used by producers to rationalize their justification for continued increased interstate prices in proceedings before the Commission.
>
> It is impossible to protect consumers against exorbitant prices unless regulation is extended to the intrastate market.

But the discrimination suffered by the interstate market at the hands of the intrastate market takes yet another form. While interstate consumers utilizing gas for low and even some high priority end uses are suffering severe if not complete curtailment, their intrastate counterparts are able to obtain gas for the lowest priority, large boiler fuel uses. As Chairman Nassikas noted before the Senate Commerce Committee in 1973,

> ...Excessive volumes of gas have been diverted from jurisdictional consumers to intrastate markets, including the combution of large volumes to generate electricity , when alternate fuels could have been utilized.

Because of this inequitable situation, Dr. Schwartz concluded in 1973 hearings before the Senate Antitrust and Monopoly Subcommittee that allocation of gas between the interstate and intrastate markets as well as regulation of intrastate prices is required:

> Last, the only way in which social priorities can be implemented on a uniform basis is to regulate both intrastate and interstate sales of natural gas. It appears that we have a dual set of standards when supplies of gas in the intrastate market are available for end uses which are drastically curtailed in the interstate sector.

In short, unless Congress takes positive action to bring the unregulated intrastate markets under FPC regulation, the shortages will worsen and the pressure to deregulate will increase. Regulation of the intrastate market is the only logical way to control the monopolistic forces which are able to manipulate the current half-regulated/half unregulated system to their private advantage and to the detriment of both interstate and intrastate consumers.

STATEMENT OF CHARLES F. WHEATLEY, JR.
GENERAL COUNSEL
AMERICAN PUBLIC GAS ASSOCIATION
BEFORE THE SUBCOMMITTEE ON ENERGY AND POWER OF THE
HOUSE COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
HOLDING HEARINGS ON S.2310,
H.R. 11265, H.R. 11047 and H.R. 9159

January 28, 1976

My name is Charles F. Wheatley, Jr. and I am General Counsel of the American Public Gas Association. I appreciate this opportunity to appear before you today to testify with respect to certain pending bills, H.R. 11265, H.R. 11047, H.R. 9159 and S.2310 (as passed by the Senate).

The American Public Gas Association consists of approximately two hundred publicly-owned gas distribution systems located throughout the United States. These systems are owned by public agencies of State and local government which are directly responsible to the people served. The people served -- or consumers -- exercise ultimate control over these systems in the same manner as the people in a larger context exercise control over Congress -- through their votes.

The American Public Gas Association has been closely involved with the question of regulation of natural gas producers. This concern stems from the fact that increases in wellhead prices by producers are transferred directly by the pipeline companies under purchased gas adjustment clauses to the City gate which must be paid by public as well as all other distributors. Recognizing the adverse impact of such increases on their consumer owners, if unjustified, the Association has participated actively in all of the major producer rate procedures at the Federal Power Commission and in the courts over the past fifteen years. The experience gained provides a valuable insight we believe, into the issues now before the Committee.

The key question facing this Committee is whether the Natural Gas Act of 1938[1/] should be amended to authorize the permanent deregulation of natural gas at the wellhead. Certain proposals such as S.2310 (as it passed the Senate) and H. R. 11265 (as introduced by Mr. Krueger) are bottomed on the premise that the existing regulatory standards of the Natural Gas Act enacted 38 years ago must be permanently abandoned as to certain wellhead sales by producers of natural gas; H.R. 11047 (as introduced by Mr. Brown of Ohio) reaches a similar result in a practical sense by authorizing deregulation of wellhead rates for sales of new natural gas for seven years. The American Public Gas Association strongly opposes these efforts to deregulate natural gas as improper attempts to jettison the existing regulatory standards of the

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[1/] 15 U.S.C. §717 *et seq*.

Natural Gas Act of 1938 which the United States Supreme Court has held on many occasions were designed to "protect consumers from exploitation by natural gas companies." 1/ The Association believes that these deregulation proposals when studied carefully and fully by this Committee and Congress based on a complete record, should be rejected as contrary to the public interest of the American people. If legislation is to be acted upon at this time, the Association supports H.R. 9159 (as introduced by Mr. Fraser) which is based on the premise that only effective regulation, not deregulation, will protect the American people from unjustified, exorbitant wellhead prices by the producers of natural gas.

The keystone thesis of the industry proponents for deregulation is that federal regulation has resulted in artifically low prices and a resultant shortage of natural gas. This thesis is repeated in full page ads sponsored by major oil companies as well as, unbelievably, publications by Administration officials supporting deregulation. At its core, this keystone concept is demonstrably false. When properly exposed through full investigation of the true facts, the entire case for deregulation crumbles. Apparently realizing this, the proponents of deregulation have sought for a vote on

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1/ Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 610 (1944).

the House floor for permanent deregulation before the matter can be thoroughly explored and reported upon by the House Interstate and Foreign Commerce Committee. Once the full facts are known, the public will reject the industry created myth blaming "federal regulation" as a cover-up for a calculated program of avoiding just and reasonable rates to American consumers in order to seek to charge prices for a domestic energy source [1] at or above those set by the OPEC cartel for foreign oil. Apropo here is Abraham Lincoln's insight: "You can fool some of the people all of the time and all of the people some of the time, but you cannot fool all of the people all of the time."

I would like to turn first to the history of regulation of natural gas in the United States to demonstrate that the central premise of the deregulation industry proponents is erroneous. Following that, I will review the specific provisions of the pending bills now before the Committee.

I. History of Natural Gas Regulation in the United States.

A close study of the history of the regulation of natural gas in the United States clearly demonstrates one central verity--since enactment of the Natural Gas Act in 1938, the major oil companies have sought one loophole after another which have eventually been closed by the Courts to protect the public interest. The present "gas shortage" campaign, which was commenced by the industry in 1969, seeks to exploit what the producers believe is another major loophole in the act -- an alleged lack of jurisdiction in the Federal Power Commission to prevent discrimination against interstate commerce by unregulated intrastate activities of natural gas companies. The present FPC has completely failed to close down the producers' attempt to exploit this latest loophole, but the matter is now before the Courts. 1/ The producers, aware that the courts could rule against them or that a subsequent FPC could exercise its present jurisdiction to prevent the rampant discrimination they have created against interstate gas users through manipulation of unregulated intrastate markets, are now making a frantic all-out push to have Congress enact permanent deregulation

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[1] Owned in large measure by the people to the extent located on Federal lands, such as the Outer Continental Shelf which is expected to produce a major part of future new gas reserves.

1/ A petition for a writ of mandamus has been filed in the United States Court of Appeals for the District of Columbia Circuit by the American Public Gas Association, Consumer Federation of America, U.S. Conference of Mayors and joined by the American Federation of Teachers and the State of Pennsylvania requesting that the Commission be ordered to exercise its existing jurisdiction under the Natural Gas Act to prevent undue discrimination against interstate users by unregulated intrastate activities of natural gas companies. See Appendix B hereto.

legislation before the next national elections. They fear, and rightly so, that if the issue of natural gas deregulation is put to the American people at the next election, the basic policy of the long-standing Natural Gas Act of 1938 for "just and reasonable" rates, insuring a fair profit return to the industry, will be solidly reaffirmed and their present interstate-intrastate loophole closed.

a. The Federal Trade Commission findings in the 1930's upon which Congress acted to enact the Natural Gas Act of 1938 have never been disproved.

As stated in the first section of the Natural Gas Act of 1938, 1/ the legislation resulted from reports of the Federal Trade Commission concluded in 1935 after extensive investigations of the natural gas industry. The central finding of the FTC was that the absence of regulation over the natural gas industry, which had grown to provide service to many of the most populous states far from the producing areas, was contrary to the public interest because of the monopoly nature of the industry. Gas would be supplied to particular areas usually through only one pipeline. Once consumers purchased expensive gas using equipment, they became captive customers, subject to paying "all the market will bear" in the absence of any effective regulation.

1/ 15 U.S.C. §717

The States had no such powers, since the matter in issue of impact on interstate commerce was beyond their jurisdiction. With respect to producers, the Federal Trade Commission noted that:

> "The 4 largest producer groups account for about 72 percent of the output of natural gas produced by 32 holding company groups in 1930."

The FTC concluded that:

> ". . . the prime characteristic of the situation described is that of a steadily developing concert of interests dominating the producing, transporting, and distribution branches of the industry." (S. Doc. No. 92, pt. 83A, 70th Cong., 1st Sess (published 1936))

The Natural Gas Act was enacted by Congress in 1938 to protect consumers from this monopoly situation.

As will be discussed *infra* the basic findings of the FTC have been reaffirmed in every adjudication considering the issue of monopolization since 1938. (See p. 15 and Appendix A.)

b. *The 1938 Natural Gas Act provides for just and reasonable wellhead rates and precludes discrimination by natural gas companies*.

The Natural Gas Act of 1938 was drawn in language patterned after that of the earlier Interstate Commerce Act, the landmark legislation establishing Federal regulation over interstate carriers. As such, it is clear that in order to protect the abuses which had been revealed by the Federal

Trade Commission, Congress intended to vest the Federal Power Commission with Congress' Constitutional powers over interstate commerce.

Section 1 of the Act broadly defines the scope of the Commission's jurisdiction over "natural gas companies" as follows:

> (a) As disclosed in reports of the Federal Trade Commission made pursuant to S. Res. 83 (Seventieth Congress, first session) and other reports made pursuant to the authority of Congress, it is hereby declared that the business of transporting and selling natural gas for ultimate distribution to the public is affected with a public interest, and that Federal regulation in matters relating to the transportation of natural gas and the sale thereof in interstate and foreign commerce is necessary in the public interest.
>
> (b) The provisions of this Act shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.
>
> (c) The provisions of this Act shall not apply to any person engaged in or legally authorized to engage in the transportation in interstate commerce or the sale in interstate commerce for resale, of natural gas received by such person from another person within or at the boundary of a State if all the natural gas so received is ultimately consumed within such State, or to any facilities used by such person and facilities be subject to regulation by a State commission. The matters exempted from the provisions of this Act by this subsection are hereby

> declared to be matters primarily of local concern and subject to regulation by the several States. A certification from such State commission to the Federal Power Commission that such person and facilities and is exercising such jurisdiction shall constitute conclusive evidence of such regulatory power or jurisdiction."

Sections 4 and 5 of the Act prescribe that all rates charged by "natural gas companies" subject to the jurisdiction of the Commission shall be "just and reasonable". Section 4(b) also bars any natural gas company from engaging in activities which constitute undue discrimination:

> "No natural-gas company shall, with respect to any transportation or sale of natural gas suject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service."

c. Producers early held subject to the Act.

In the initial proceedings to be adjudicated by the Federal Power Commission, it was established that producers were subject to the Commission's jurisdiction. In the first case to reach the Supreme Court concerning the 1938 Act, Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 610 (1944) the Court affirmed an FPC holding that gas produced by an interstate pipeline company was subject to "just and reasonable regulation. The Supreme Court reaffirmed this conclusion in two other decisions in the mid-1940's, Colorado Interstate Gas Co. v. Federal

Power Commission, 324 U.S. 581 (1945), rehearing denied, 325 U.S. 891 (1945) and Interstate Natural Gas Co. v. Federal Power Commission, 331 U.S. 682 (1947), rehearing denied, 332 U.S. 785 (1947). In the Interstate case, the Court held:

> "We have held that these sales are in interstate commerce. It cannot be doubted that their regulation is predominantly a matter of national, as contrasted to local concern. All the gas sold in these transactions is destined for consumption in States other than Louisiana. Unreasonable charges exacted at this state of the interstate movement becomes perpetuated in large part in fixed items of costs which must be covered by rates charges subsequent purchasers of the gas, including the ultimate consumers. It was to avoid such situations that the Natural Gas Act was passed."

Thus, contrary to the present contention of the producers that wellhead regulation was not established until the "unfortunate" decision of the Supreme Court in 1954 in the first Phillips case (Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954), it was clear that such regulation was imminent from the very first decisions of the Court interpreting the Natural Gas Act, establishing Commission jurisdiction over production operations of interstate pipeline companies. That the producers were under no such delusions in the 1940's was obviously from their efforts to seek to amend the Natural Gas Act to deregulate wellhead sales prior to 1950.

d. President Truman vetoes producer efforts to deregulate natural gas at the wellhead as contrary to the public interest.

The producers commenced in 1947 to push for legislation amending the Natural Gas Act to exempt their wellhead rates. After such a bill had narrowly passed the House by a two vote margin, it was vetoed by President Truman on April 15, 1950. President Truman noted the "concentration of ownership of natural gas reserves" and stated that the continuation of FPC jurisdiction to regulate wellhead rates was necessary to

> "adequately protect the public interest by permitting the Commission to prevent unreasonable and excessive prices, which would give large windfall profits to gas producers, at the expense of consumers, with no benefit to the Nation in terms of additional exploration, and production."

e. Producer efforts to obtain administrative deregulation of wellhead rates defeated by Supreme Court in first Phillips case.

Subsequent to President Truman's veto, the producers directed their efforts at creating a loophole to appointments to the Federal Power Commission with the advent of a Republication Administration in 1951. The new Commission under Chairman Kuykendal, ruled that it lacked jurisdiction over wellhead sales by "independent producers" of natural gas. On appeal by the State of Wisconsin, the United States Court of Appeals and United States Supreme Court firmly held, as had been clear from earlier decisions and the legislative activities, that wellhead rates of producers were subject to the Commission's jurisdiction under the terms of the 1938 Act. Phillips Petroleum Co. v. Wisconsin 347 U.S. 672 (1954). The Supreme Court's reasoning as to the need for wellhead regulation perceived by Congress was quite incisive on the need to protect consumers:

> "Regulation of the sales in interstate commerce for resale made by a so-called independent natural-gas producer is not essentially different from regulation of such sales when made by an affiliate of an interstate pipeline company. In both cases, the rates charged may have a direct and substantial effect on the price paid by the ultimate consumers. Protection of consumers against exploitation at the hands of natural-gas companies was the primary aim of the Natural Gas Act. Federal Power Com. v. Hope Natural Gas Co. supra (320 US at 610). Attempts to weaken this protection by amendatory legislation exempting independent natural-gas producers from federal regulation have repeatedly failed, [footnote omitted] and we refuse to achieve the same result by a strained interpretation of the existing statutory language." [347 U.S. at 685]

Thus, the producers' efforts to obtain deregulation through administrative interpretation was defeated.

f. A second legislative effort at deregulation vetoed by President Eisenhower.

The producers, feigning surprise and outrage at the Supreme Court's Phillips decision, returned to Congress with a massive lobbying campaign to obtain deregulation. The grossness of some of their activities, when revealed, so incensed President Eisenhower, that he vetoed the Kerr-McGee Act in 1955. The door to these direct loophole efforts having been closed by the Courts and President, the producers settled down to a long period of relative stability under wellhead regulation until 1969.

g. Wellhead regulation until 1969 revealed a narrow range of differences as to the proper wellhead rate.

The period of regulatory history pertaining to producer rates up to 1969 was one of relative stability for industry and consumers. It was during this period that the concepts of cost of service area rate regulation were crystallized and confirmed by the Commission and the courts.

The major point of significance was that though the rate proceedings were hotly disputed on all sides, the range of differences between consumer parties on the one side and producers on the other as to the proper wellhead rate was relatively small. In the first Southern Louisiana Area Rate Case.1/ the producers were seeking only about 2¢ per Mcf more than the amount awarded by the Commission and confirmed by the courts. Similarly, the FPC established rates of

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1/ Southern Louisiana Area Rate Proceeding (Southern Louisiana I), 40 FPC 530 (1968) *modified*, 41 FPC 301 *rehg. denied*, 41 FPC 616 (1969), *aff'd sub nom.*, Austral Oil Co v. FPC, 428 F.2d 407, *on rehg*, 444 F.2d 125 (5th Cir.), *cert. denied sub nom.*, Municipal Distributors Group v. FPC, 400 US 950 (1970).

approximately 20¢ per Mcf for new gas were only some 2¢ higher than the rates urged by consumer representatives as proper. The zone of controvery among the major parties to the proceedings was thus quite narrow and reflected the fact that the proper costs of producing fair rate of return can be identified and quantified within reasonable limits.

While the rates sought by the producers in the area rate proceedings were close to those adjudicated by the Commission, the producers did seek to establish another loophole by contending that their "contract rates" should be adopted as the "just and reasonable rates." The producers based this claim on the contention that workable competition existed to assure reasonable rates. These contract rates greatly exceeded the final adjudicated raes in many instances. Extensive hearings were held on this contention in area rate cases. In each instance, based on the facts of record, the Company contentions were found contrary to the facts and rejected by every Presiding Administrative Law Judge, Commission and court to consider the issue. A synoposis of some of these decisions is attached hereto as Appendix A. These conclusively demonstrated, based on exhaustive records and evidence presented by the producers, that consumers cannot be protected through reliance on the voluntary contract rates proposed by producers.

In general, the wellhead rates for producers were set based on cost-of-service principles including a fair rate of return. All of the companies' costs were allowed, including dry hole costs, and the return allownace was computed to place them among the highest earnings of any U.S. industry.

The history of producer regulation under the Natural Gas Act up to 1968 reveals a fair belance between the consumer protection requirements of the Act and industry fair treatment. During the period of 30 years since enactment in 1938, the natural gas industry grew and prospered.

Records indicate that interstate sales of natural gas increased on an average of about 6% per year during this period. Pipelines filed regular expansion dockets with the Federal Power Commission to meet the expanding markets. Certificates were issued by the Commission based on findings of reserves adequate to support the new markets in annual growth. During this period the percentage of new reserves of gas dedicated to the interstate markets maintained a relatively constant ratio with respect to the reserves dedicated to the intrastate markets. About 75% of the total new gas went to interstate users, or approximately 25% went to intrastate. Pipelines entered firms contract with distributors for the deliveries of specified volumes of gas. The distributors in turn invested funds for expansion of their systems and the attachment of new customers based on their firm contract entitlements with the pipelines. The entire industry was progressing on a sound, solid businesslike foundation--all premised on fair and proper regulation of wellhead rates. Thus, the history of regulation resulted in a growing healthy natural gas industry, based on a fair regulated profit. All of this was to crumble with the advent of the "gas shortage" campaign of the producers inaugurated in 1969.

g. De Facto deregulation by the Federal Power Commission since 1969, coupled with the producers' "gas shortage" campaign to exploit a new believed loophole in the Natural Gas Act, is responsible for the present gas situation.

The thirty year history of solid growth averaging about 6% per year under regulation has been reversed since 1969. Since that time of the new discoveries of natural gas in the United States, approximately 92% are now dedicated to the intrastate market, while only 8% are dedicated to the interstate market. No new expansion dockets are being filed by the interstate pipelines companies -- instead, curtailment cases are the order of the day wherein the pipelines seek to renig on their firm contracts with distributors based on certificated gas supply findings previously confirmed by the Federal Power Commission. The entire contract structure between pipelines and distributors upon which the industry was based have been thrown out by the Commission in various curtailment cases, without provision for just compensation to the adversely affected parties. From a picture of solid health and growth, the interstate gas business has been sorely afflicted by the activities of producers since 1969.

The turn-around can be pinpointed to the establishment of the "gas shortage" campaign by the producers in 1969. The campaign followed after a decision by the United States Supreme Court in the Permian Basin Area Rate Cases, 390 U.S. 747 (1968) in which the Supreme Court rejected the producers' claims relating to gas supply. The Supreme Court noted that in each year reported findings of new gas reserves by the American Gas Association Reserve Committee had exceeded the production in the year. Similarly, in 1968 the Federal Power Commission decided the First Southern Louisiana Area Rate case in which it made similar findings rejecting the producers' arguments relating to declining reserves. While the producers lost these cases in the sense that they were seeking area rates approximately 2¢ per Mcf higher than the rate established by the Commission in each instance, they widely proclaimed that there would be a gas shortage. The following spring of 1969 when the AGA Reserve Committee reported the reserve data for 1968, for the first time the new reserves reported for the year were less than the production for the year. Subsequently analysis of the AGA figures revealed that this resulted from a downward revision by the Committeee of its prior-years' estimates of gas reserve, not from any decline in drilling activity or in new gas well discoveries. 1/ It appeared quite clear that the gas reserves had been revised downward by the industry AGA Reserve Committee from the prior-years' estimates, without explanation or detail as to the justification therefor.

1/ The AGA Reserve Committee, its membership and results are discussed *infra*.

Coupled with the "gas shortage" campaign by the producers which focused on the new AGA reserve report issued in the spring of 1969, was the appointment of a new chairman of the Federal Power Commission, who announced that a new regime of producer regulation would be inauguarated. The statement by Chairman Nassikas was prophetic--the FPC underwent a change of direction and policy from one of cost-of-service regulation at the wellhead to one of de facto deregulation of producers.

The actions by the FPC since 1969 relating to producer wellhead regulation have constituted a series of end-runs around the regulatory principles of the Natural Gas Act. Many of these have been reversed by the courts on review. A number of these can be briefly reviewed.

First, the Commission in 1970 issued an order seeking to reopen the First Southern Louisiana Area Rate case. In the reopened proceedings, the producers supported a settlement proposal which was ultimately adopted by the Commission in July of 1971. Under the "settlement" the approximately $350 million in refunds due to consumers under the First Southern Louisiana Area Rate case was either forgiven outright or permitted to be "worked off" by future dedications of gas. The settlement raised the price for new gas to 26¢ per Mcf at the wellhead from the approximate 20¢ per Mcf level then in existence. A crucial part of the "settlement" was a moratorium which extended until 1977 under which the producers agreed that the 26¢ per Mcf with some escalation would provide the incentive for the development of needed additional gas supplies in the future.

But before the ink was dry on the Second Southern Louisiana settlement by the producers, the Federal Power Commission issued Order 455 establishing the optional pricing procedure which completely circumvented the pricing structure which the producers had agreed to be effective through 1977. Under the optional pricing plan, producers could file for an increase in rates over and above the established area rate ceilings. The first case to reach the courts under the optional pricing proceedings, the Belco case, was reversed by the United States Court of Appeals for the District of Columbia Circuit for failing to provide evidence to justify the proposed 45¢ rate over and above the 26¢ area rate ceiling.

A second end-run around established regulatory procedures was the Commission's proposal that sales of gas for 180 days not be subject to the wellhead price ceilings. The 180 day deregulation proposal was reversed by the United States Court of Appeals in a suit brought by the Consumer

Federation of America and the American Public Gas Association. The United States Supreme Court denied certiorari, leaving the Court of Appeals' decision stand.

In 1974, the Commission inaugurated a new approach--a nationwide area rate for new gas. In Opinion No. 699, the Commission initially proposed a 42¢ wellhead rate. On rehearing, the Commission simply added 8¢ by using the previously rejected discount cash flow technique, to porpose a nationwide rate for new gas of 50¢ per Mcf with various escalators for the future.

In December of 1975, the Commission ordered a drastic increase for the price of old gas discovered prior to January 1, 1973. The receords submitted by the Company under oath had indicated their cost of this gas including a 15% overall rate of return. (16-19% on equity) ranged in the order of 20-21¢ per Mcf. The Commission Staff proposed a non-cost add-on of 3 1/1¢ per Mcf. The Commission exceeded the proposal of its Staff by ordering a 29¢ per Mcf price for old gas based on the unproved assumption that producers were incurring income tax costs based on elimination of the depletion allowance.

In mid-19[illegible]5, the Commission issued RM75-25 which permitted customers of interstate pipelines to enter direct purchase contract with producers [illegible] rates above the area rate ceilings, with provision for the gas to be wheeled to them by the interstate pipeline companies. Here again, the Commission appears to be engaging in an effort leading to further deregulation of natural gas prices.

The underlying premise of the FPC's de facto deregulation campaign since 1969 has been that the Commission is powerless to deal with the efforts of the natural gas companies subject to its regulation to pursue what they believe is a major loophole in the Natural Gas Act. The producers, joined by the Commission, take the position that the Commission lacks jurisdiction to prevent discrimination against the interstate market by natural gas companies of gas in the intrastate market at unregulated prices. The attempt to exploit this represents the latest in a series of efforts by the producers since enactment of the Natural Gas Act in 1938 to find and exploit a new loophole.

The American Public Gas Association, Consumer Federation of America, U.S. Conference of Mayors and other consumer groups believe that the present loophole upon which the industry has hinged their "gas shortage" campaign since 1969, supported by the de facto deregulation efforts of the Commission is completely unjustified and contrary to the terms of the present Natural Gas Act. These consumer parties have filed a petition for a writ of mandamus with the United

States Court of Appeals for the District of Columbia Circuit for an order directing the Commission to exercise its jurisdiction under the present Natural Gas Act to prevent the existing discrimination by natural gas companies in their intrastate activities against the interstate market. The facts which have developed since 1969 wherein instead of 75% of the new gas going to interstate users, only 8% is so devoted, with the balance of 92% going to unregulated intrastate markets, poses a situation of an undeniable discrimination against interstate commerce. The Natural Gas Act authorizes the Commission to preclude such discrimination, and the Supreme Court has earlier held that the Interstate Commerce Commission, based on similar wording of the ICC Act, possesed jurisdiction to preclude similar type discrimination. Attached hereto as Appendix B is a copy of the Petition for Writ of Mandamus filed in the United States Court of Appeals. That Court ordered the Federal Power Commission to respond to the Petition and permitted producers to file a brief therein. The matter is now under adjudication by the Court.

h. Investigation of gas shortage claims by producers reveals major discrepancies.

Unbelievable as it may seem, the entire "gas shortage" claims by the producers rests on unverified data. At their core, the claims rest on reports of the Reserve Committee of the American Gas Association. That Committee is composed of representatives of the major producers. The underlying data on which the Committee members prepare their reports have been kept confidential and have never been made public. Analysis of the AGA reports commencing in 1969 (for calendar year 1968) has revealed some dramatic unexplained inconsistencies. The estimates that prior years' reserves have sharply nose-dived indicating a reevaluation by the Committee members of their prior years' estimates of reserves. No justification or explanation of this downward revision, supported by substantiating data, has ever been presented by the Committee. In the Second Southern Louisiana Area Rate case, the Staff of the Federal Power Commission proposed questionnaires to the Commission which would have elicited the underlying data and facts upon which an independent evaluation could be made as to the validity of the reported reserves. The Commission refused to permit the collection of this data by the Staff. Instead, the Commission undertook a series of orders which resulted in increasing the rate for gas from 20¢ to over 50¢, based on the reserves as reported by the AGA Committee, without any investigation or proof as to their validity.

Recently, however, a number of matters have come to light which establish quite conclusively that the AGA figures are unreliable and overstated. Some Staff members of the Federal Power Commission undertook a study, based on records obtained from interstate pipeline companies of some 31 leases in the Outer Continental Southern Louisiana area. Based on their study of reserve data, the Staff concluded that the 31 leases in question had in fact 54% more proved gas reserves than the AGA had reported for the entire Outer Continental Shelf Area involving over 800 leases. This was dramatic concrete proof that the AGA figures, when actually verified, were grossly understated. The Federal Power Commission, however, whitewashed this report in its Order in the nationwide area rate case for new gas, Opinion No. 699. The Commission admitted that the Staff report was valid, but simply took the additional new gas which the Commission had found in the 31 leases and tacked it on to the AGA reported reserve figures for the nation as a whole and used the new figure as a basis for computing the new gas rate of 50¢ per Mcf. This was patently fallacious. Once the AGA figures had been revealed to be grossly understated by the Staff report, the results should have been the rejection of the AGA figures in toto and the collection of new independent data as a basis for determining the proper rate.

The Staff of the Federal Trade Commission has also undertaken a confidential study of AGA reported reserves.

The witnesses testifing before Congress from the FTC have indicated that the AGA figures were grossly underreported, when compared with other company internal records of reserves. Unfortunately, the final FTC report has not yet been made public, nor has the data upon which the FTC staff based its testimony.

Finally, investigations by the House Interstate and Foreign Commerce Committee have revealed other irregularities where producers have withheld gas supplies from the interstate market. The results of these investigations further indicate the unreliability of the producer "gas shortage" claims as a basis either for administrative action by the FPC in setting new rates, or as a basis for claiming a need for deregulation of natural gas at the present time.

II. Present Campaign By Producers For Deregulation Is Unjustified And Premature.

The producers are mounting an obvious frantic campaign to have Congress pass permanent deregulation at the present time. A review of the history of regulation under the Natural Gas Act clearly reveals that the present state of events has not been the result of regulation by the Federal Power Commission at the wellhead, as claimed by the producers.

The 30-year history of regulation up to 1968 produced a pattern of growth, firm contractual arrangements among all segments of the industry, and a premise wherein the industry could function and consumers were supplied. It has only been with the inauguration of the producers' gas shortage campaign in 1969, accompanied by the *de facto* deregulation efforts of the Federal Power Commission, and the withholding of gas by the producers or the diverting of such gas through an assumed loophole from the interstate markets to intrastate markets, that the present chaotic situation has come about. But the producers cannot afford to perpetuate this chaos indefinitely into the future. If a firm regulatory premise is reestablished, as had existed up through 1968, history has shown that the producers will bring forth gas supplies at reasonable rates, and growth and development of the gas industry will resume.

The key to termination of the present producer created campaign is the removal of the loophole which the producers believe they have found whereby gas may be siphoned away from the regulated interstate market into the unregulated intrastate market. The clear discrimination that is presently resulting from the activities of natural gas companies against interstate consumers to diversion of gas supplies to unregulated intrastate markets damages not only the interstate consumer, but also adversely affects the intrastate consumer who must pay exorbitant unregulated prices for natural gas. The closing down of this loophole is thus essential to terminating the present state of producer-created chaos. The loophole can be closed, we believe, by action of the courts in interpreting the scope of the Commission's present jurisdiction under the Natural Gas Act of 1938. That Act requires the Commission to prevent undue discrimination against interstate users. The Commission's refusal to enforce the Act is similar in many respects to the Commission's refusal in the early 1950's to regulate independent producer rates at the wellhead. As the courts quickly closed that purported loophole, so again at the present time, we believe the courts will and should close the present loophole opened by the producers activities in the past few years to exploit the unregulated intrastate market to the detriment of the national interest.

Failing action by the courts to close the loophole, Congress itself should act to deal with the matter. The states have not and cannot regulate the activities by the producers so as to ensure a uniform allocation of natural gas among all users in the nation on an equal basis. The absence of any effective regulatory controls will mean that the American consumers would be completely unprotected. Just as the producers have been able to play-off the unregulated intrastate market against the interstate markets to its detriment, any widening of regulatory controls would place the interstate consumer in the same posture as the United States now finds itself vis-a-vis the OPEC nations with respect to oil supplies.

Furthermore, it is clear that the chaos in the natural gas industry since 1969 has directly resulted from de facto deregulation. The producers request that regulatory controls be removed will increase the problem, rather than solve them. The producers will be unwilling to commit supplies of natural gas under deregulation for any period of time at a certain price for fear that the following year they could have obtained a much higher price. The wide-spread use of favored nation clauses or other escalator clauses would return.[1/] The result would be that any increase by any producer in any contract would result in increase of all wellhead prices for producers under such clauses. There can be no firm planning, either by pipelines or distributors, as to their purchased gas costs in terms of evaluating their expenditures for improvements and developments to connect new supplies. In short, a vote for deregulation would be a vote to continue the chaotic shortage situation of the present natural gas industry.

1/ This is already happening in Alaska.

I would now like to turn to a brief analysis of the pending bills before the Committee.

III. Analysis Of Pending Bills To Amend The Natural Gas Act.

The natural gas legislative proposals now before the Committee are set forth in the Committee print of January 20, 1976. This embraces four proposals: (1) S-2310 (as passed by the Senate); (2) HR 11265 (as introduced by Mr. Krueger); (3) HR 11047 (as introduced by Mr. Brown of Ohio); and (4) HR 9159 (as introduced by Mr. Frazier).

a. S. 2310 as passed by the Senate.

Title I, Emergency Natural Gas Authority of this Act is clearly now unnecessary and moot. Section 102(a) states "The Congress finds and declares that the Nation will suffer severe shortages of natural gas during the heating season from November 1975 through March 1976." This was the original claim put forth by the industry, the Federal Power Commission and the Federal Energy Administration in the fall of 1975--at a time when legislation to deregulate natural gas was then pending before the Senate. Subsequent studies by the General Accounting Office and the Congress' Office of Technology Assessment in the early fall of 1975 revealed that the shortage anticipated for the coming winter was overstated and not likely to occur. The Federal Energy Administration on

December 25, 1975 conceded that prior estimates of severe shortage for the coming winter would not materialize. While the justification for the change was that the weather was warmer than usual in the early part of the winter, certainly the weather in the recent weeks of the winter has been more severe than normal, and yet the severe shortage originally predicted will not materialize.

The fear of shortage, and the full-page advertisements by producers and announcements by FEA that factories would be closed, jobs would be lost, obviously had an impact on the Senate when it considered S. 2310. Had the true facts been known, it is difficult to say what action the Senate would have taken relating to natural gas legislation.

On page 4 of the Act, Section 104 the principle of treating even a short-term gas emergency by exempting the wellhead price from regulation for onshore gas is wrong. The promise of deregulation of natural gas provides the producers with an incentive not to sell gas to interstate pipelines at a regulated price and to withhold existing gas supplies. The correct principle, we believe, for solving any threatened gas supply problem is to vest the Federal Power Commission with allocation authority to allocate the available supplies of natural gas across the nation on a non-discriminatory basis to assure that all users will be treated equally. It is clearly obvious from the vast quantities of boiler fuel and low-priority uses being made of natural gas in the intrastate markets, amounting to major portion of the total gas consumed in the United States, and for which alternate fuels are available, that there is no reason for high priority essential uses of gas anywhere in the United States to be subject to possible curtailment. Thus, the proper legislative approach towards solving the problem would be to insure that the Federal Power Commission undertakes its duty to allocate the available gas supplies on a fair and non-discriminatory basis. At its heart, this problem may not be a legislative one for Congress because under the existing Natural Gas Act it appears that the Federal Power Commission does have legislative authority to prevent discrimination against interstate commerce. The problem exists in the failure of the Commission to exercise its existing legislative powers to prevent the unjust discrimination taking place between interstate and the intrastate markets.

Page 6, line 7-9 would permit a interstate pipeline to buy from its wholly-owned affiliate at an unregulated price, provided that the pipeline makes at least one purchase from another producer at the high level it desires to make from its affiliate. Obviously this is a loophole which would permit pipeline companies to in effect set their own price for their own gas production to the detriment of their consumers. This is clearly not in the public interest and pipeline producers should be entitled to no more return on their operations than the pipeline itself receives for its transportation functions.

On page 7, line 6, the cap proposed for prices during the emergency period is set at the "highest wellhead price . . . at which natural gas was sold during the period of June 1, 1975-August 1, 1975 in the state in which such first sale is made." While the principle of the cap may be beneficial, the language of the bill by permitting the highest single sale to set the ceiling price is unwarranted. There will always be some small sale at some exorbitant price which would then become the standard for the ceiling -- this is unfair and arbitrary to consumers and highlights the complete lack of protection in the bill to consumers against unnecessary, unjustified high prices by producers.

Section 105, commencing on page 7, dealing with the "prohibition of use of natural gas as boiler fuel" by the Federal Energy Administrator, has a major loophole in it. The amendment to Section 2 of the Energy Supply and Environmental Coordination Act of 1974 by the addition of a new subsection (e) would allow the administrator to prohibit any power plan or major fuel burning installation from burning natural gas if --

> "(vi) The prohibition under this subjection will result in making natural gas available to sale to a natural gas company which transports natural gas in interstate commerce and which does not have adequate supplies of natural gas to meet the requirements of its high priority consumers and which it is curtailing pursuant to a curtailment plan on file with the Commission . . ." (p. 9, lines 1-8)

Thus, the case of power plants or major fuel burning installations in intrastate markets where the gas would be conserved by an order of the administrator would be simply made available to the intrastate pipeline and not automatically available to an interstate pipeline company in curtailment, the FEA administrator would lack authority to order the closing of the plant. This poses a major loophole in the Act, which would allow most of the present large boiler fuel uses in the intrastate market to continue. The only boiler fuel uses that would be subject to curtailment would be those served by interstate pipeline companies in the present interstate market. Thus again, the bill reveals that it is clearly designed to benefit the small handful of producing states to the detriment of the rest of the states of the country. The compensation provisions in Section 105(d) commencing on page 10, line 20, while well meaning, will be very difficult to administer, and will lead to extended litigation. It will be extremely difficult to determine who the beneficiaries would be from the curtailment of large boiler fuel uses. The language of the Act would tend to permit a termination that would permit a rolled-in increase in prices to all consumers of an interstate pipeline, and thus adversely affect the high priority residential and small commercial customers. Furthermore, the compensation provision has no time limit and it is not tied to any existing contractual rights of the boiler fuel user. For example, if the boiler fuel user has an interruptible contract with no contractual rights to any particular quantity of gas service, what would be the measure of its damages?

Section 107 of the Act commencing on page 12, line 14 should be rejected as bad in theory and policy. The section would allow curtailed consumers of natural gas to purchase natural gas directly from producers at unregulated prices and require the transportation of that gas by interstate pipeline companies. The section in essence seeks to enact the provisions of the FPC's Docket RM75-25 into law. The legality of the Commission's rulemaking proceeding is now in litigation before the courts. The major failing of the procedure set forth in Section 107 is that it would permit the disruption of the integrity of the franchises established by the nation's gas distributors and furthermore, would permit the siphoning off of available gas supplies to the large corporations having the ability to pay higher unregulated prices, while small users, dependent on regulated prices would be subject to curtailment. Thus the provision would permit large users to buy available gas supply at high, unregulated prices and thereafter lock up the available transportation capacity in the nation's pipelines to the detriment of the small, high-priority users. The provision is clearly incompatible with any scheme of rational, reasonable regulation for all Americans large and small on an equal basis.

The inability of the procedure of Sections 107 to provide any protections to Americans is clear from the language on page 13, commencing with line 4, which declares that the transportation of gas exempted from the provision is declared to be a matter of local concern subject to regulation by the several states and the authorization of a certification by the state commissions that it has regulatory jurisdiction over the rates and service. It is clearly impossible to expect that 10 different states, through which an interstate pipeline might travel from a producing area to the area of use would be able to effectively regulate the transportation of gas as it proceeds through their state. Similarly, in the state of production where the gas is purchased by the large user directly from a producer, it is unreasonable to believe that the production state will have any incentive to set reasonable ceilings to protect unwarranted prices by producers for gas which would be used in another state. Finally, any semblance of state regulatory commission jurisdiction over what is clearly an interstate transaction may be unconstitutional. The Supreme Court has held in the past that efforts to regulate what is in fact interstate commerce by the state violates the Constitution and it is doubtful whether Congress can delegate its Constitutional powers to the states in this regard. The present situation in the country where intrastate prices have skyrocketed reveals the truth that the states in which the producers operate have no desire or capability to provide any effective regulation of these rates. As Chairman Nassikas of the Federal Power Commission pointed out, the high intrastate rates are 2-3 times in excess of any rate which could be deemed justified under any semblance of fair, regulatory controls.

In Title II, Section 203, p. 15, line 5, the bill would deregulate "new natural gas after April 4, 1976." Page 16, commencing at line 6 defines new natural gas to mean gas produced "from wells initiated or completed in an extension of a previously discovered reservoir on or after January 1, 1975." This is clearly a large loophole. All of the old gas wells in the country could simply be plugged and new well drilled right along side the old well to obtain the new natural gas unregulated price. This would be wasteful of our natural resources, but the Act has no safeguards to prevent such abuses. This points up the obvious fact that any bills based on the premise that new gas would be completely unregulated with the price skyrocketing up to levels set for oil by the OPEC nations, while seeking to hold the line on supposed "old gas" in effect will lead to complete and total deregulation of natural gas. The producers know this and for that reason are supporting the provisions of S. 2310.

The provisions in Section 24(a) commencing on page 22, line 19, to establish a national ceiling for new gas from offshore federal lands from January 1, 1975 to December 31, 1980 are highly illusory.

First, the factors which the Commission has been directed to consider, appearing on page 23, lines 5-22 would institute a completely new test beyond those which have been established by the courts under the previous area rate regulation cases since 1960. This will breed uncertainty, which in turn will foster the continued withholding of natural gas. Clearly, the existing standards of the Natural Gas Act which have been worked out for many years and closely considered by the Commission and the courts on review thereof, should not be jettisoned at this time. These standards, in general allow the companies to receive all of their costs plus a fair rate of return.

On page 24, line 14, the section appears to authorize advance payments. This would be an improper action for the Congress to take. The Federal Power Commission itself has finally come to the conclusion that the advanced payment program should be terminated. This is a necessity because the advance payments in essence represent a double compensation for the producer in the form of a free loan or grant in many cases from the consumers, followed by payment of an area rate which in turn is designed to provide full compensation to the producer. In other words, the advance payment is in fact a bonus windfall to the companies. The recognition of this fact by the Federal Power Commission in its recent order terminating the advance payment program should not be resurrected by Congress.

On page 25, commencng with line 3, the bill provides for the establishment of an interim national rate for offshore gas, "which shall be equivalent to the average dollar value per barrel of domestic crude oil" expressed in equivalent Btu's. This is a completely fallacious standard which would result in the nation's consumers paying for domestic supplies of natural gas, owned by the United States on Federal lands, at a rate computed by domestic oil prices, which in turn have been pegged in relationship to price increases effectuated by the OPEC cartel. It is completely improper to set the wellhead price of natural gas in relationship to the wellhead price of oil because of the completely different set of costs which are involved in transmitting and delivering that gas to the American consumer. For years in the New England area prior to the present gas shortage period, the price of natural gas at the burner tip was very close to the price of oil, despite the fact that at the wellhead, natural gas prices were less than half of the wellhead oil prices. The reason for this is that the extensive transportation and distribution facilities required to distribute natural gas are much more expensive than those required to process and market oil. There has never been in the history of the country any equalization of gas and oil and the wellhead on a Btu basis and any attempt to do so or to force such an equalization will immediately have the impact of subjecting gas consumers throughout the nation to non-competitive rates whereunder they will be paying prices greatly in excess of oil.

But as captive customers locked into their investment in their gas using equipment, they will have no options to switch to a lower price fuel. Because of their captive status, Congress originally enacted the Natural Gas Act in 1938 to prevent their exploitation. Any legislation which sets the price at the wellhead for natural gas above a "just and reasonable" level which insures the oil companies a fair profit among the highest levels of American industry, does an unfair injustice to the American people.

On page 32, the new provisions setting forth new factors for the termination of old gas prices in lines 15 through page 33, line 14, establish new tests other than those established by the Commission and the courts in the long history of prior rate regulation. The net result would be the creation of an entire new round of complicated litigation and controvery over the meaning of the existing regulatory standards. Congress should not depart from the existing regulatory principles which have been thoroughly considered and adjudicated in prior decisions. For example, the inclusion of "the prospective costs of operation" on page 32, line 18, for old gas would inject a completely new element into old gas determination. The Supreme Court in the Permian Basin case has affirmed a regulatory standard for old gas, based on actual cost of service during the test year in question.

Finally, the provision on page 36, commencing at line 3 to permit the intrastate transportation of gas in interstate pipelines free from regulatory jurisdiction of the Federal Power Commission, should be rejected. This is a patent attempt to overrule the Supreme Court's decision in the Lo Vaca case. 1/ That case held that when intrastate gas is commingled with interstate gas in an interstate pipeline facility, the Federal Power Commission alone should have jurisdiction to determine whether the arrangement meets the public convenience and necessity under the standards of Section 7 of the Natural Gas Act. The exemption of this would create difficult problems.

b. HR. 11265 as introduced by Mr. Krueger.

This bill is similar in many respects to S. 2310, so that the comments relating to S. 2310, set forth above, are applicable thereto.

The bill has some changes and differences from S. 2310, which must be studied carefully. For example, while the bill in the boiler fuel prohibitiion authorization by the Federal Energy Administration on page 7 continues the loophole of S.2310 for power plants and other large boiler fuel

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1/ 379 U.S. 366 (1965).

installations located in the intrastate market, and not connected to interstate pipelines, it also goes further and seeks to eliminate the exemption definition for small utility generating plants. The definition in Section 103(4) of "boiler fuel use of natural gas" in the page 3 definitions of S. 2310, commencing at line 19, is omitted from H.R. 11265 on page 3. This appears to evidence an attempt to close out the small private and municipal generating systems located around the country which are dependent on natural gas for their continued liability. Furthermore, the definitions section of H.R. 11265 eliminates the definition of "essential user" as found in S. 2310 relating to high priority consumers of natural gas. This broadens the scope of the emergency deregulation provision considerably.

On page 24, line 9, the bill considerably expands the definition of new natural gas which would be subject to deregulation under the bill by permitting gas "after the expiration of a contract by its own terms" to be classified as new natural gas. This results in a windfall profit to the producers, and gives them a vested incentive to make any existing contracts of short duration. There is no reason why old natural gas which has already been developed at an old cost should automatically receive the high windfall profits of deregulated price merely through the happenstance of the expiration of a contract term.

c. H.R. 11047 (as introduced by Mr. Brown of Ohio).

This bill is essentially a modification of an emergency bill, to extend the emergency period for seven years as shown on page 3, line 20. However, when reviewing other sections of the bill, such as page 4, lines 12-13, the bill refers to certain one-year emergency periods ending, for example, on April 15, 1976. Thus, the bill apparently would permit during the one-year emergency period for contracts to be entered for a seven-year duration, at unregulated prices. This appears inconsistent because if the emergency period is only one year, there would be no need to permit contracts that would sell gas at a deregulated price over seven years. Thus, the bill is inherently unsound.

As previously discussed in relationship to S. 2310, emergency legislation would now appear to be moot.

d. H.R. 9159 (as introduced by Congressman Fraser).

In general, the Association supports the Fraser bill as the best consumer bill dealing with natural gas, assuming that legislation is imperative at this time.

The major beneficial provision of the bill is that it would establish a nationwide rate for gas, regardless of where located in the United States. This would permit the fair, equal regulation and allocation of natural gas to all users in the country on just and reasonable terms.

We suggest certain minor perfecting amendments to the bill. On page 3, line 1, the definition of"boiler fuel use of natural gas" needs to be amended to include the provisions which have been adopted in S. 2310 to exempt therefrom uses by an electric utility system where either the total system does not have a net generating capacity of more than 150 megawatts regardless of the size of the units involved, or if it does exceed 150 megawatts, the unit in question is 25 megawatts or less. This language would verify the need to protect small generating systems throughout the country from total extinction and destruction of their existing investment in generating facilities for their communities.

On page 13 of the bill, the hearing provisions should be strengthened by eliminating the word "limited" and the words "in its discretion" from the evidentiary hearing provisions. An evidentiary hearing does not require an extensive amount of time, and does provide due process justice to all parties concerned.

We would suggest an amendment of the judicial review provision to provide the judicial review may not be had only if the initial rate set is not in excess of the rate set in Order 699 and 699-H, which has had complete judicial review.

On page 15, the provision allowing small producers to obtain 50% higher rates than large producers should be eliminated. History has shown that a proper rate for large producers is also a proper rate for small producers and there is no need for an exemption to permit a different level.

This Court as early as 1958 in Bel Oil Corp. v. FPC, 255 F.2d 548, 551, 553 (5th Cir.), cert. denied, 358 U.S. 804 (1958) observed as follows:

> Upon the reconvened hearing petitioners introduced additional evidence tending to show that petitioners did not possess any dominating position in the industry, that natural gas is competitive with other non-regulated fuels, that the proposed prices were comparable with unregulated prices for local consumption; that maintenance of such a price is necessary to provide appropriate incentives for exploration and production of natural gas in Louisiana.
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> We do hold that evidence of unregulated prices in the field is not sufficient to warrant a finding by the Commission that a price comparable to them is just and reasonable within the intendment of the Natural Gas Act. Neither is evidence of the field price when coupled with the opinion of experts that the price must be high enough to provide an incentive for exploration and development of new sources of supply.

This Court reiterated the holding of the Bel Oil case in its decision in United Gas Improvement Co. v. FPC, 290 F.2d 133, 135 (5th Cir.), cert. denied sub nom., Sun Oil Co. v. United Gas Improvement Co., 368 U.S. 823 (1961):

> As we have previously stated in Bel Oil Corp. v. F.P.C., 5 Cir., 255 F.2d 548, 553, a price paid for gas as the result of arm's length bargaining with the producer is not, merely because bargained for in a highly competitive market, "just and reasonable" within the intendment of the Natural Gas Act, 15 U.S.C.A. § 717 et seq. See also New York Public Service Comm. v. F.P.C., D.C. Cir., 287 F.2d 143. This is so because the only justification for giving the Commission the duty to regulate prices was the determination by Congress that the producers have a supply that is so restricted in relation to demand that they have the economic power to bargain for prices that will be injurious to the public. "The purpose of the Natural Gas Act was to underwrite just and reasonable rates to the consumers of natural gas." Atlantic Refining Co. v. P.S.C., 360 U.S. 378, 388.

In Permian Basin Area Rate Proceeding, 34 F.P.C. 159 (1965), in which the Commission issued its first area rate decision, it found the record to be completely devoid of any evidence of effective competition between the producer-sellers, which it did not find surprising in view of the complete absence of bargaining incentive or leverage on the part of the pipeline-purchasers:

> In considering the appropriate guidelines for regulating producer rates on an area basis, we must dispose of one threshold argument. Certain of the producers contend that their contract prices should be approved as meeting statutory requirements because they have been reached as a result of what is termed effective competition. IPAA contends that the examiner erred in not adopting as the standard for determining area prices the "market value" as established by natural gas purchase contracts negotiated at arm's length. [34 F.P.C. at 180-81.]

* * *

The essential difficulty with the contract price argument is that there is nothing in this record which would justify a conclusion that reliance on contract prices unrelated to cost will "afford consumers a complete, permanent and effective bond of protection from excessive rates and charges," which is the purpose of the Act in prescribing that the rates and charges to consumers of natural gas should be just and reasonable. Atlantic Refining Co. v. Public Service Commission of New York (CATCO), 360 U.S. 378, 388 (1959). See Wisconsin v. Federal Power Commission, 373 U.S. 294, 309-310 (1963). Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672, 685 (1954). There are admittedly many producers selling gas to the interstate pipelines both in the nation as a whole and the Permian Basin in particular, but nothing in this record suggests that any competition among them in making sales to the pipelines is in any way adequate to assure that the public will secure gas at just and reasonable prices in the absence of regulation. [34 F.P.C. at 181]

* * *

The pipelines are far from being in a bargaining position which would validate the theory that a market price will necessarily be a just and reasonable price. On the contrary, the entire history of pipeline purchasing activity, since the end of the El Paso monopoly in the Permian Basin, has been characterized by the overriding needs of the pipelines to contract for the large blocks of uncommitted reserves essential to maintain their competitive position in developing markets (see United States v. El Paso Natural Gas Co., 376 U.S. 651 (1964)) and their inability to accomplish this objective except as [sic] ever increasing prices. The abstention of the pipelines from these proceedings does not indicate that any significant change can be expected in the future. The fact that many pipelines are themselves producers with an interest in generally higher producer prices also cannot be overlooked. [34 FPC at 182]

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In United Gas Improvement Co. v. F.P.C., 290 F.2d 133, 135 (CA5-1961), certiorari denied 368 U.S. 823 (1961), it was said that the supply of gas controlled by the producers is so restricted in relation to demand that they have economic power to bargain for prices that will be injurious to the public. The Court held that the Commission in exercising its authority may not act merely upon proof that the prices in question were arrived at as a result of arm's-length negotiation, but must look behind the negotiated price. See also P.S.C. of New York v. F.P.C., 287 F.2d 146 (CADC-1961), United Gas Improvement Co. v. F.P.C., 287 F.2d 159 (CA10-1960). In so holding the court was reiterating the position it had taken in a series of cases involving just and reasonable rates for independent producers under Section 4 of the Act in which it had concluded that:

> * * * evidence of unregulated prices in the field is not sufficient to warrant a finding by the Commission that a price comparable to them is just and reasonable within the intendment of the Natural Gas Act. Neither is evidence of the field price when coupled with the opinion of experts that the price must be high enough to provide an incentive for exploration and development of new sources of supply. 18/

If there is a case to be made for effective competition among producers in establishing just and reasonable rates it has not been made on this record. There is no evidence of competition between producers to make new sales by offering lower prices. On the contrary the primary competition revealed by the record was among the pipelines to secure new gas supplies at higher prices. Whatever the degree of competition which may exist among producers it has not been effective to afford gas consumers the protection to which they are entitled under the Natural Gas Act. Under these circumstances, there is no basis for assuming that prices which "have leaped from one plateau to the higher levels of another" will constitute a level which will be "the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest." Catco, supra, at pages 391, 388. [footnote omitted]

18/ Bel Oil Corp. v. F.P.C. 255 F.2d 548, 553 (CA5-1958) certiorari denied, 358 U.S. 804....[34 FPC at 182-83.]

The United States Supreme Court, in its affirmance of the Commission's *Permian* opinion, specifically noted the anticompetitive nature of the gas producing industry:

> The field price of natural gas produced in the Permian Basin has in recent years steadily and significantly increased. *These increases are in part the products of a relatively inelastic supply and steeply rising demand; but they are also symptomatic of the deficiencies of the market mechanism in the Permian Basin.* Producers' contracts have in the past characteristically included indefinite escalation clauses. *These clauses, in combination with the price leadership of a few large producers, and with the inability or unwillingness of interstate pipelines to bargain vigorously for reduced prices, have created circumstances in which price increases unconnected with changes in cost may readily be obtained.* These market imperfections, operative despite an "essentially monopsonistic environment," have accentuated the consequences of inelastic supply and sharply rising demand. Once an increase has been obtained by the larger producers, the escalation clauses have guaranteed similar increases to others. In contrast, consumers have been left without effective protection against steadily rising prices. Their alternative sources of energy are in practice few, and the demand for natural gas, particularly in California, is therefore relatively unresponsive to price increases. The consumer is thus obliged to to rely upon the Commission to provide "a complete, permanent and effective bond of protection from excessive rates and charges." *Atlantic Rfg. Co. v. Public Service Comm'n*, supra, at 388, 3 L. Ed. 2d at 1319. [*Permian Basin* Area Rate Cases, 390 U.S. 747, 793-95, *rehearing denied,* 392 U.S. 917 (1968) (footnotes omitted; emphasis supplied).]

In 1968, in its *Southern Louisiana I* opinion, the Commission reaffirmed its earlier finding in *Permian* that contract prices are *per se* unjust and unreasonable because of the lack of competition in the market caused both by the control of a great percentage of reserves by a few large producers and by the weak bargaining position of pipelines, resulting from, inter alia, a lack of any incentive to negotiate for lower prices since the entire cost of the gas may be passed on to the consumer and also because most pipelines have producing affiliates and thus favor higher producer prices:

> We are again faced in this proceeding with the contention that the interstate market for natural gas is effectively competitive, and that our statutory responsibility for establishing just and reasonable rates will be discharged by a validation of the contract prices. We considered this claim in Permian and decided that while negotiated contract prices are an important element for consideration in the determination of area rates, the requirements of the Natural Gas Act cannot be satisfied by reliance on contract price levels as the basic regulatory standard upon which to base just and reasonable rate levels. We adhere to that position in this case. Further, we do not believe that competition in the markets for natural gas, as the facts of that competition in Southern Louisiana are shown in the record, has been or will be adequate to assure consumers just and reasonable rates. Accordingly, we reject regulation by contract price in this decision. [Southern Louisiana Area Rate Proceeding, 40 F.P.C. 530, 552 (1968).]
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> The record here indicates that the costs of the individual producers vary substantially, but there is no evidence that these cost differentials have been reflected in the negotiated prices. While certain aspects of the gas producing industry, such as lease acquisition activity, are undoubtedly competitive, there is no evidence of substantial price competition in the sale of gas to pipelines.

Another factor inherent in the consideration of contract prices is the relative bargaining position of sellers and purchasers. We considered this problem in Permian, and concluded that the pipelines purchasing gas in the Permian Basin were so disadvantaged in their bargaining position as to invalidate the concept of regulation by contract price. We reach the same conclusion here. This record discloses that eight independent producers in Southern Louisiana accounted for over 50 percent of 1960 sales under FPC rate schedules (interstate sales). The record here does not disclose any data showing the amount of uncommitted reserves controlled by any producer or group of producers, but the pattern of sales commitments and annual deliveries indicate that a small number of sellers control a large percentage of the gas reserves in Southern Louisiana. We point out that while the necessary information concerning uncommitted reserves is exclusively in the possession of the producers themselves, they have made no showing to rebut a conclusion that there is a concentration of control over the uncommitted reserves in Southern Louisiana.

The large interstate pipeline purchasers in Southern Louisiana periodically require the long-term commitment of large blocks of reserves, as we have pointed out. At any one time the latitude available to the pipelines as to reserve sources or purchasing timing is very circumscribed. Only a few producers may have the necessary volumes available for initial commitment at the moment. Moreover, pipelines pass their gas purchase outlays on to distributors, and ultimately to consumers, through the pipelines' regulated, cost-based resale rates, which is a factor tending to dilute their bargaining motivations. This entire situation enhances the bargaining power of the sellers and often tends to make price a second level consideration to the purchaser.

Based upon this analysis we must conclude that there are serious market imperfections which preclude us from relying upon the free operation of the market, as evidenced by arms'-length bargaining, to protect the ultimate consumer from unreasonable purchased gas rates.

> This conclusion is entirely consistent with the judicial determinations relevant to the issue of contract prices. See, Bel Oil Corp. v. F.P.C., 255 F.2d 548 (CA5-1958), cert. denied 358 U.S. 804 (1958); City of Detroit v. F.P.C., 230 F.2d 810 (CADC-1955); Forest Oil Corp. v. F.P.C., 263 F.2d 622 (CA5-1959); Atlantic Refining Co. v. P.S.C. of New York (CATCO), 360 U.S. 378 (1959); U.G.I. Co. v. F.P.C., 283 F.2d 817 (CA9-1960); P.S.C. of New York v. F.P.C., 287 F.2d 146 (CADC-1960); U.G.I v. F.P.C., 287 F.2d 159 (CA10-1961); U.G.I. v. F.P.C. 290 F.2d 133 (CA5-1961), cert. denied 368 U.S. 823 (1961); U.G.I. v. Callery Properties, Inc., 382 U.S. 223 (1965). For the most recent opinion of the Supreme Court on the subject see F.P.C. v. Sunray DX Oil Co., et al., 391 U.S. 9, 25-26 (1968). [40 F.P.C. at 553-55.]

In affirming the FPC's Southern Louisiana I opinion, this Court sustained the FPC's use of cost pricing and rejected the use of market prices:

> At the outset, however, we are met with the contention that the very method of cost pricing is too imprecise to be used in regulating the gas-producing industry. We must reject this contention. In a situation wherein the Commission has found that market imperfections tend to force price to excessive levels, it would be self-defeating to regulate on the basis of market forces, and the most logical alternative is usually cost pricing. Thus the fact that it cannot be made absolutely precise is not grounds for rejecting cost pricing when market conditions make its use advisable. Indeed, some courts have held that costs must be at least the starting point for fixing just and reasonable rates in the gas industry. E.g., City of Detroit v. FPC, 1955, 97 U.S. App. D.C. 260, 230 F.2d 810. Even more persuasive is the fact that the Supreme Court upheld the use of cost pricing on a record similar to ours in its Permian decision. [Austral Oil Co. v. FPC, 428 F.2d 407, 432, rehearing denied, 444 F.2d 125 (5th Cir.), cert. denied, sub nom., Municipal Distributor Group v. FPC, 400 U.S. 950 (1970) (footnote omitted, emphasis supplied).]

In light of the unanimous conclusion of the Supreme Court, the Commission and this and all other courts to consider the matter that because of the anti-competitive nature of the gas producing industry, the contract or "actual" market price is not, indeed cannot be, the just and reasonable rate, and since the unregulated, intrastate contract prices of 55¢ to $1.05 are the same as or less than the prices of alternative fuels, which in turn determine the "commodity value" of gas, it follows like night from day that the producers' claim that the "commodity value" is the just and reasonable rate or "true" market price is not only patently fallacious but in fact rendered specious in view of the present shortage situation in the industry. In making their claim that the "commodity value" is equivalent to the "true" market price, the producers cite the United States Supreme Court's decision in Federal Power Commission v. Sunray DX Oil Co., 391 U.S. 9 (1968), as the basis therefor. The Supreme Court explained its statement in Sunray DX concerning the "true" market price in its recent opinion in Federal Power Commission v. Texaco, Inc., 417 U.S. 380, 41 L. Ed. 2d 141, 156-57 (1974), in which the Court once again emphasized that the market price cannot be the just and reasonable rate under the Natural Gas Act:

> For the purposes of the proceedings that may occur on remand, we should also stress that in our view the prevailing price in the market place cannot be the final measure of "just and reasonable" rates mandated by the Act. It is abundantly clear from the history of the Act and from the events that prompted its adoption that Congress considered that the natural gas industry was heavily concentrated and that monopolistic forces were distorting the market price for natural gas. Hence, the necessity for regulation and hence the statement in Sunray DX, supra, 391 U.S. at 25 [-26], 20 L. Ed. 2d 388, that if contract prices for gas were set at the market price, this
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>> "would necessarily be based on a belief that the current contract prices in an area approximate closely the 'true' market price -- the just and reasonable rate. Although there is doubtless some relationship, and some economists have urged that it is intimate, such a belief would contradict the basic assumption that has caused natural gas production to be subjected to regulation [and which must have underlain this Court's CATCO decision -- namely, that the purchasing pipeline, whose cost of purchase is a current operating expense which the pipeline is entitled to pass on to its customers as part of its rates, lacks sufficient incentive to bargain prices down.]" (Footnote[s] omitted.)

Thus, in Texaco and in Sunray DX the Supreme Court determined that the raison d'etre for the regulation of producer prices under the Natural Gas Act was that the unregulated "actual" market price of natural gas bears no relationship to the statutory standard of "just and reasonable", and the Court also established that the "true" market price is equivalent to the just and reasonable price. The "true" market price is not equal to or greater than the "actual" market price since as the Supreme Court observed in Texaco,

> Congress rejected the identity between the "true" market and the "actual" market price. [417 U.S. 380, 41 L. Ed. 2d 141, 157.]

Since the "commodity value" of gas is, according to the producers, equal to if not greater than the "actual" market price, which as illustrated above is for numerous reasons per se unjust and unreasonable, and since a major purpose for regulating producer prices is to protect consumers from paying the "actual" market prices in this patently anticompetitive market, the "commodity value" of gas is not, indeed cannot be, "just and reasonable" under Sections 4 and 5 of the Natural Gas Act, and, hence, the "commodity value" of gas cannot be equated to the "true" market price as that term is used by the Supreme Court in Texaco and Sunray DX.

The D.C. Court of Appeals applied the Texaco holding in Consumer Federation of America v. FPC, ____U.S. App. D.C._____, 515 F.2d 347, 357 (1975), cert. denied Supreme Court No. 75-227, 44 U.S.L.W. 3225 (Oct. 14, 1975), in striking down as unlawful the Commission's attempt to deregulate 180-day sales of natural gas by producers to the interstate market:

> "Even if the producers charged the interstate pipelines no more than they charged other bidders in the unregulated intrastate market, Texaco took occasion to 'stress that in our view the prevailing price in the market place cannot be the final measure of "just and reasonable" rates mandated by the Act.'"

Most recently, the Fifth Circuit rejected the producers' position that "just and reasonable" interstate rates could be set at the level of unregulated intrastate prices, because it found the unregulated intrastate market uncompetitive:

> "Specifically, the producers base their argument for higher rates on a comparison between the FPC's new rate for natural gas and higher price of both oil and natural gas in the unregulated intrastate market. They argue that the national rate for regulated gas should equal the 'commodity value' of gas determined by comparison with substitutable fuels such as oil. In essence, these petitioners would have us set the price of natural gas at the rate that the market would bear. The commodity price of gas would most likely be set by the prevailing price of oil and the cross-elasticity of demand between gas and oil. To accept this free market 'commodity value' would be to eschew the congressionally

> mandated responsibility of rate regulation which is devised to reach a 'just and reasonable' rate. Fixing a "just and reasonable' rate for a product sold in an inherently uncompetitive market requires more than mere subservience to national and international market forces." [Shell Oil Company v. FPC, slip op. at 185 (5th Cir. Oct. 14, 1975) (emphasis supplied).]

SUMMARY STATEMENT OF
CELIA STAR GODY

Before the Subcommittee on Energy and Power
House of Representatives
January 28, 1976

My name is Celia Star Gody. I am an economic consultant and statistician and am Senior Vice President of Foster Associates, Inc., a Washington-based firm providing economic consulting services in the area of governmental regulation of business and in energy economics. I have conducted numerous studies of the economics of natural gas and of natural gas contracts over a period of 20 years.

My statement will deal with the impact of the legislative proposals for partial deregulation of the prices for interstate gas sales. The studies made by Foster Associates on this subject, on behalf of the Natural Gas Supply Committee, are directed to the effect of legislation which would lift FPC controls for new gas sales, sales from new wells, and deliveries under renewals of contracts which expire by their own terms. It is assumed that so-called "old" interstate gas would remain under FPC regulation. I am aware that one of the proposals now under consideration would maintain FPC controls on new gas from the OCS area until 1981. While the Foster Associates study, which was completed in March 1975, did not focus on this aspect of the current legislative proposals, the results of the study are nevertheless applicable.

Although no one can make definitive forecasts of gas prices, gas volumes, and all the other variables entering into estimates of the impact of deregulation, we do have available a solid factual basis for at least part of the projections. The Foster Associates study of impact of deregulation, unlike other studies which have been made of the subject, is based on a detailed examination of the natural gas interstate contracts filed with the FPC. The study covered for each sale the contract prices, volumes, contract provisions, expiration dates, and FPC price ceilings both currently and to 1980. The study included the larger volume sales which in the aggregate account for 70 to 75 percent of interstate gas supply. The information from this large sample of contracts was expanded to obtain estimates for total interstate sales.

I want to discuss first the dollar impact of deregulation of new gas sales and expiring contracts. For this purpose, our study used three different estimates of the unregulated market price: $1.25, $1.50, and $1.75. I will present the results here only for the assumption of a market price of $1.75. The estimates for the alternative prices are shown in the Foster Associates study.

The first question to consider is: which interstate sales would go up in price under the current legislative proposals. These would be:

(1) Sales of new gas under future contracts;

(2) Sales under expiring contracts on renewal;

(3) Sales under limited-term and emergency contracts on termination.

First, let us consider the interstate gas sales which would be made under future contracts even with continued regulation. New-gas commitments averaged 560 billion cubic feet per year during 1969-1972 in terms of annual delivery volumes. In 1973 and 1974, as intrastate prices moved up, the lion's share of the new-gas supplies went to the intrastate market and the commitments to the interstate market dropped to about 275 billion cubic feet per year, again in terms of annual delivery volumes. If we assume that about the same volume would be sold interstate in the future with continued regulation, the cost impact is estimated as $0.15 billion in the first year and $1.35 billion in the fifth year of new-gas deregulation.

Looking next at the expiring contracts, the cost impact is very gradual because most of the gas contracts now in force are long-term contracts for a term of 20 years. Based on our detailed study of the contracts, we conclude that by the end of the first year only one percent of the total volume would be covered by expiring contracts and by the fifth year the expiring contracts would cover only 18.4 percent of the pre-1975 interstate gas volume. If we use the $1.75 estimate of unregulated prices, the price would increase by the difference between the $1.75 market price and the prices applicable under FPC regulation. In dollars, the impact would be $0.06 billion in the first year and would increase to $1.6 billion in the fifth year. This estimate assumes that every contract which expires would be renegotiated at the market price, but some sellers in some areas may not succeed in renegotiating to this price level.

Finally, we need to consider the limited-term and emergency sales. About a year ago, when we made our impact studies, we estimated the cost impact of such gas at $0.12 billion per year. However, the volume of such sales is now only half as large as our estimated volume and it may be doubtful whether any impact estimate should be included for such sales.

Combining these figures, we have a cost impact of $0.33 billion in the first year and $3.1 billion in the fifth year, as shown below and in Attachment 1 to my statement.

These impact estimates are computed using the present FPC ceiling prices as the base from which prices escalate with deregulation, but it is reasonable to assume that the FPC price ceilings will increase even with continued regulation.

Consequently, the fifth-year impact is overstated for this reason.

	(Billions of Dollars) First Year	Fifth Year
Expiring Contracts	$ .06	$1.63
Emergency Sales	.12	.12
New Gas (250 Bcf/yr.)	.15	1.35
	$ .33	$3.10

The impact estimate of $3.1 billion in the fifth year is admittedly a sizable amount, but it is only a fraction of the estimates which have appeared in some studies. The question arises whether we have omitted any types of sales where there would be a cost impact. It has been suggested that old gas contracts which have price redetermination clauses or so-called deregulation clauses would move up in price. Under the pending legislative proposals, it is my understanding that all "old" sales, except renewals of expiring contracts, would remain subject to FPC regulation. Therefore, such contract provisions would operate only within the limits of the FPC national rate ceilings for old gas. Should we include new gas supplies which might be forthcoming with deregulation but which will not be available with continued regulation? Obviously, there is no cost impact here because the higher prices will be paid only for the extra supplies that are found as a result of the increased incentive and that would not have been found and developed with the existing regulated prices. In fact, to the extent that the unregulated market price is lower than the price of alternative energy fuels, the availability of additional gas supplies reduces the net cost impact of deregulation. Moreover, pipeline transportation costs are essentially fixed costs; the unit costs obviously will be lower when spread over larger gas volumes than with a smaller throughput.

In all of the estimates discussed above, it has been assumed that "new" gas from the OCS (that is, new sales and renewals of expiring contracts) would be sold at the estimated market price of $1.75. If such sales are subject to an FPC ceiling, or to an interim price based on Btu equivalence with OCS crude oil, the cost impact would probably be less than is indicated here.

Several studies have appeared which make very high projections of the net cost of deregulation. A report by the Congressional Research Service projects the impact of the "Pearson-Bentsen-Krueger" bill in the first year as $12.7 - $14.8 billion, excluding the cost of additional supplies which might be developed as a result of deregulation. The report further suggests that these costs would increase by $3.8 billion each year.

This report is obviously not based on any factual studies and the estimates made demonstrate a complete lack of familiarity with the operations of the natural gas industry and with industry statistics. First, CRS assumes that, with deregulation, new-gas prices would move to $2.50 per Mcf. This estimate of the unregulated market price is far above the estimates shown by the studies of others, including the Federal Power Commission, the General Accounting Office, and the Federal Energy Administration. As support for the $2.50 market price, it is stated that prices for recent interstate emergency sales have ranged from $1.70 to $3.00 per Mcf, averaging $2.62. The highest price identified for any emergency sale by a gas producer is $1.75. The recent sales have ranged in price from $0.51 to $1.75 and the average price in the last quarter of 1975 was $0.86.

More important, the CRS report makes grossly erroneous assumptions concerning the volumes of gas which would escalate in price as a result of the pending legislative proposals. The report assumes that 9.6 - 10.6 trillion cubic feet of gas would move up in price in the first year and an additional 2.0 trillion would be subject to price escalation each year; thus, by 1980, 17.6 - 18.6 trillion cubic feet would have escalated in price. This is a ridiculous conclusion in light of the fact that total marketed production for the "Lower 48" may be projected at 14-15 trillion cubic feet by 1980 if the recent decline trends continue.

Attachment 2 to my statement shows the CRS estimates and the corrections required to those estimates. The largest part of the impact shown by CRS is for intrastate sales. CRS shows 5.0 Tcf of intrastate gas moving up in price from $1.25 to $2.50 per Mcf. CRS apparently assumes that virtually all intrastate sales are spot sales but in fact most of the gas sold intrastate is under long-term contracts. Until recently, 80 to 90 percent of the intrastate sales, in terms of volume, were under contracts for a term of 10 years or more. Even in 1974 and 1975, some two-thirds of the total new-contract volume was under long-term agreements. To the extent that intrastate contracts can be renegotiated, they have already been free to do so. Nevertheless, even though intrastate market prices were moving up sharply in 1974 and 1975, the volume covered by contract renegotiations averaged less than 0.5 Tcf per year or about five percent of the intrastate volume. Adding the new-contract volume, of perhaps 0.5 Tcf, the total intrastate volume which is free to escalate in price initially is more reasonably estimated at 1.0 Tcf, or 20 percent of the 5.0 Tcf assumed by CRS.

CRS also computes an impact of $1.3 billion for pipeline non-jurisdictional sales. Such gas is purchased by the pipelines from producers, mainly under intrastate contracts but in some cases under interstate agreements. To the extent that prices for such sales would increase, the increase would typically result from an increase in the price paid to producers and from operation of the purchased-gas adjustment clauses in the pipeline contracts. Since the impact of price increases under producer contracts is already included in the CRS estimates, it would be double-counting to include a separate impact for the pipeline nonjurisdictional sales.

For OCS gas, CRS assumes that the total volume is 1.9 Tcf and that all sales will escalate to the new ceiling price, assumed as $1.60 per Mcf. Total production from the offshore area is substantially higher than 1.9 Tcf, a fact readily ascertainable. However, the only sales from the OCS which would be free to escalate in price would be new gas and expiring contracts. New-gas sales from the OCS have averaged only 0.18 Tcf in recent years, so that the total impact here is $0.18 billion, or less than 10 percent of the CRS estimate of $1.9 billion. (Expirations of OCS contracts have been included in the Attachment 2 corrected data with other interstate contract expirations.)

For new onshore gas, CRS assumes that 0.7 billion would be committed even with continued regulation and that the cost of deregulation is the escalation in price for such supplies. In fact, recent commitments of onshore gas have averaged less than 0.10 Tcf or 14 percent of the CRS estimates. Similarly, CRS estimates contract expirations at

1.0 Tcf annually, while the detailed Foster Associates study shows only 0.29 Tcf for 1976.

Correcting these erroneous estimates, as shown on Attachment 2, we derive a cost impact for 1976 amounting to $1.1 billion, rather than the $12.7 billion shown by CRS. In fact, even if one were to accept CRS's estimate of a $2.50 market price and to correct only the volume figures, the impact would be reduced from the $12.7 billion shown in the report to $2.17 billion.

Another study recently issued was that prepared by the General Accounting Office. The GAO study presents some thoughtful discussion of the considerations affecting natural gas deregulation, including the relationship between the interstate and intrastate gas markets, the impact on industrial and residential consumers, the effect on the national economy, balance of payments effects, and environmental effects.

The GAO report shows a "net cost" of deregulation peaking at $13.0 billion in 1980. Unfortunately, in making its projections of prices under the alternative assumptions of deregulation and continued regulation, GAO gave no specific consideration to legislative proposals which would lift controls only for "new" gas and maintain FPC regulation for "old" gas, excluding renewals of expiring contracts. Thus, the projections also directed to the total-deregulation situation. Moreover, GAO gave no consideration to the existing provisions of long-term contracts which would keep prices from rising to the level of the unregulated market price even if regulatory controls were lifted. GAO recognized this limitation of its study, stating:

> "Raising the average price for lower 48 gas to $2.10 per Mcf [at the city gate] within 5 years may, in fact, be too rapid an increase due to the fact that natural gas is usually sold under long-term contracts, but it serves to present a reasonable upper limit to the economic consequences of deregulation." (Page 4)
>
> "Also these cost projections are based on the assumption that the deregulated average price would rise to $2.10 (city-gate) by 1980 which is a rapid increase and probably would require renegotiation of some existing contracts. These calculations are made to establish the maximum probable costs of deregulation." (Page 44)

If we accept the structure and projections in the GAO report but take separate account of new and old gas price levels, the estimates made by GAO of "net cost" of deregulation as of 1980 are reduced from $13 billion to a range of $2 - $4 billion. The computations are shown in Attachment 3 to my statement. The volumes shown in the Attachment are from the GAO report. They have been split between "old" gas and "new" gas in accordance with the information developed from the Foster Associates contract study. GAO assumed, under continued regulation, annual price increases of five cents per Mcf for interstate gas and 15 cents per Mcf for intrastate gas. We have assumed these same escalations for interstate gas, but have applied them separately to new and old supplies; for intrastate volumes, with continued regulation, we assume annual escalations of five cents for old contracts and 10 cents for new contracts, including renegotiations. With new gas deregulation, GAO assumed that all prices would reach $1.75 per Mcf in the field ($2.10 at the city-gate) by 1980. We have assumed that all new gas would go to $1.75 but that old gas, both interstate or intrastate would move up by 5-10 cents per Mcf annually. The result of these corrections is to reduce the "net cost" shown by GAO for 1980 from $13 billion to $2 - $4 billion.

I should state that I do not adopt the GAO projections of volumes and prices as being realistic and have developed the figures in Attachment 3 only for the purpose of illustrating the order-of-magnitude estimates which would result if one takes account of the provisions of existing long-term contracts.

Returning to the Foster Associates studies, I will next discuss our estimates of future field prices for interstate gas with deregulation of new sales and expiring contracts. The quantities of new supplies which will be developed with a relaxation of regulatory controls cannot be predicted. Our study used three alternative estimates. The "Medium" estimate involved the assumption that new-gas volumes would be sufficient to maintain interstate production at approximately the 1973-1974 levels. New gas production volumes could reach these levels with industry-wide annual reserves additions amounting to 17 trillion cubic feet, nearly 80 percent higher than the average for 1968-1973. Alternative estimates were made for new-gas volumes 25 percent lower and 25 percent higher than the "Medium" estimate.

We have computed the prospective field prices by using the existing FPC prices for "old" gas, together with the estimated market prices of $1.25 - $1.75 for gas which would be deregulated. Using the "Medium" estimate of new-gas volumes and the estimated market price of $1.75 for new sales, the average price in the field would increase from 31 31 cents per Mcf as of January 1, 1975 to 53 cents as of January 1, 1977 and 95 cents per Mcf as of January 1, 1980. These are rolled-in figures reflecting the estimated prices for all interstate supplies, including the new volumes which would be delivered only with the incentive of the higher prices resulting from the removal of controls on new gas sales.

No estimate was made in our study of prospective field prices with continued regulation. If it is assumed that FPC prices will increase by five cents per year, both for old gas and new gas, the regulated price in 1980 would be about 60 cents per Mcf, compared to 95 cents under the deregulation scenario. On the other hand, under the continued-regulation assumption, the interstate volume decreases by about 20 percent to 1980. With partial deregulation, our "Medium" volume estimate shows volumes increasing slightly over the period.

A final question considered in our study was the increase in costs to the residential gas consumer which might be anticipated with rising prices in the field. In 1974, the cost of gas in the field accounted for about 19 percent of the price paid by the residential consumer, with the balance representing the costs of transportation and distribution. The cost of natural gas to the residential consumer, on an average nation-wide basis, was $1.50 per Mcf as of January 1, 1975. With annual consumption of 120 Mcf per customer, the average cost of residential gas service at that date was estimated as $180 per year. Estimates of future cost increases due to rising field prices were derived using the $180 cost as the base.

The increase in consumer costs is gradual because the higher unregulated prices would be applicable only over a period of time. New gas would come onstream only gradually and sales under renewals of expiring contracts would also build up slowly. Measured from January 1, 1975, the increase in costs to the residential consumer is estimated in the range of $6 - $13 annually after one year, increasing to $45 - $83 per year after five years. The year-to-year increase averages 4.6 to 7.9 percent annually, depending on the assumptions for market price and volumes.

Using a market price of $1.75 per Mcf for new sales and expiring contracts and the "Medium" estimate of new-gas supplies, the average cost to the residential consumer increases gradually from $180 per year to $256 as of January 1, 1980. The year-to-year increase amounts to $11 in the first year, $15 or $16 in succeeding years, and $18 in the fifth year, or an annual increase of six to eight percent per year.

As was the case in connection with the estimates of future field prices, the estimates of costs of residential gas service are measured from the existing levels. These costs will increase, though to a lesser extent, even with no change in existing regulatory policy. Under continued FPC regulation, the average price will rise as contracts expire and become eligible for "new-gas" price ceilings and as the proportion of gas under new contracts and from new wells increases. Moreover, it is reasonable to anticipate that FPC would increase its price ceilings over time even with continued regulation.

The Foster Associates study of impact was carried only to 1980. However, the information in the study provides some valuable insights into the situation beyond 1980. Our study of the interstate contracts shows that the gas volumes under all contracts initiated prior to January 1, 1975 may be expected to decline by about seven percent per year under FPC regulation. Assuming this same trend for later years, by 1985, interstate production in the "lower 48" from gas now under contract would be less than half the 1974 volume and would be only 20 percent higher than the amount consumed by residential customers in the past year. These figures show that in the long term, interstate gas supply is almost entirely dependent on the quantities of new gas reserves which will be committed to the interstate market in the future. This clearly underlines the need for an increased incentive for finding and developing larger supplies of gas reserves and for the commitment of more supplies to the interstate market.

Attachment 1

FOSTER ASSOCIATES STUDY OF IMPACT OF DEREGULATION

1. Cost Impact of New-Gas Deregulation

	First Year		Fifth Year	
	Volume (Tcf)	Billion Dollars	Volume (Tcf)	Billion Dollars
New sales which would be made with continued regulation	.12	$ .15	1.12	$1.35
Renewals of expiring contracts	.05	.06	1.45	1.63
Emergency sales	.12	.12	.12	.12
Total interstate		$ .33		$3.10

2. Average Field Prices With New-Gas Deregulation

(Medium New-Gas Volumes and Unregulated Market Price at $1.75)

January 1, 1975	31.2¢ (Actual)
January 1, 1976	40.4
January 1, 1978	66.1
January 1, 1980	94.7

3. Projected Annual Cost of Residential Gas Service With New-Gas Deregulation

(Medium New-Gas Volumes and Unregulated Market Price at $1.75)

January 1, 1975	$180 (Base)
January 1, 1976	191
January 1, 1977	206
January 1, 1978	222
January 1, 1979	238
January 1, 1980	256

Attachment 2

CONGRESSIONAL RESEARCH SERVICE IMPACT ESTIMATES AND CORRECTIONS THERETO

	Price		Price Increment	Volume Escalating (Tcf)	Impact (Billion Dollars)
	From	To			
Congressional Research Service					
Intrastate	$1.25	$2.50	$1.25	5.0	$ 6.3
Non-jurisdictional pipeline sales	1.25	2.50	1.25	1.0	1.3
OCS gas	.60	1.60	1.00	1.9	1.9
Onshore gas	.60	2.50	1.90	.7	1.3
Additional reserves	--	2.50	--	3.0	7.5
Old interstate gas (expirations)	.60	2.50	1.90	1.0	1.9
Total					$20.2
Total, excluding additional reserves					$12.7
Corrected					
Intrastate	$1.25	$1.75	$ .50	1.0	$ .50
Non-jurisdictional pipeline sales	.75	--	--	None	--
OCS gas	.60	1.60	1.00	.18	.18
Onshore gas	.60	1.75	1.15	.10	.12
Additional reserves	--	1.75	--	3.0	5.25
Old interstate gas	.60	1.75	1.15	.29	.33
Total					$ 6.38
Total, excluding additional reserves					$ 1.13

Attachment 3
Page 1 of 2

REPORT BY THE COMPTROLLER GENERAL OF THE UNITED STATES
IMPLICATIONS OF DEREGULATING THE PRICE OF NATURAL GAS

A. Illustrative Revision of Data to Show New and Old Gas Prices Separately

		1980	
	1975	Continued Regulation	New-Gas Deregulation
Volumes (Tcf)			
Interstate			
Old	9.9	4.7	4.7
New	.1	1.0	1.0
Expiring contracts	.1	1.3	1.3
Total	10.1	7.0	7.0
Additional supply	--	--	1.5
Intrastate			
Old	9.4	4.0	4.0
New (incl. reneg.)	1.0	6.0	5.2
Total	10.4	10.0	9.2
Supplemental gas	0.9	1.1	1.1
Alternate fuels	--	3.3	2.6
Prices (Cents/Mcf)			
Interstate			
Old	32	57	57-82
New	60	85	175
Expiring contracts	60	85	175
Total	33	66	96-113
Additional supply	--	--	175
Intrastate			
Old	42	67	67-92
New (incl. reneg.)	125	175	175
Total	50	132	128-139
Supplemental gas	175	175	175
Alternate fuels (city gate)	210	210	210
Cost (Billion $)			
Interstate			
Old	$ 3.17	$ 2.68	$ 2.68-3.85
New	.06	.85	1.75
Expiring contracts	.06	1.11	2.28
Total	$ 3.29	$ 4.64	$ 6.71-7.88
Additional supply	--	--	2.62
Intrastate			
Old	3.95	2.68	2.68-3.68
New (incl. reneg.)	1.25	10.50	9.10
Total	5.20	13.18	11.78-12.78
Supplemental gas	1.58	1.93	1.93
Pipeline transportation costs at 35¢/Mcf	7.49	6.34	6.58
Alternate fuels	--	6.93	5.46
Total	$17.56	$33.02	$35.08-37.25

Note: The volumes and prices for "old" and "new" interstate and intrastate gas are shown only for purpose of illustration.

B. Estimates Shown in the Report by the Comptroller General

		1980	
	1975	Continued Regulation	New-Gas Deregulation
Volumes (Tcf)			
Interstate, total	10.1	7.0	7.0
Additional supply	--	--	1.5
Intrastate, total	10.4	10.0	9.2
Supplemental gas	0.9	1.1	1.1
Alternate fuels	--	3.3	2.6
Prices (Cents/Mcf)			
Interstate, total	35	60	175
Additional supply	--	--	175
Intrastate, total	50	125	175
Supplemental gas	175	175	175
Alternate fuels (city gate)	210	210	210
Cost (Billion $)			
Interstate, total	$ 3.54	$ 4.20	$12.25
Additional supply	--	--	2.62
Intrastate, total	5.20	12.50	16.10
Supplemental gas	1.58	1.93	1.93
Pipeline transportation costs at 35¢/Mcf	7.49	6.34	6.58
Alternate fuels	--	6.93	5.46
Total	$17.81	$31.90	$44.94

Report for
Natural Gas Supply Committee

THE IMPACT OF DEREGULATION ON NATURAL GAS PRICES

Foster Associates, Inc.
Washington, D. C.
March 1975

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APPENDIX A

Technical Note

I. Summary and Overview

This report presents information on the impact on field prices and consumer costs of the Administration's proposals for partial deregulation of the prices for interstate gas sales. The report updates the study made by Foster Associates, Inc., for the American Petroleum Institute, in August 1973, The Impact of Deregulation on Natural Gas Prices. The present report focuses on the impact of partial deregulation, with regulatory controls lifted for new gas sales, sales from new wells, and gas deliveries under renewals of expiring contracts. It is assumed that "old" gas would remain under FPC regulation until such time as the existing contracts expire by their own terms.

Since the preparation of the earlier report, the "energy crisis" has assumed a central role in the debate concerning national economic policy. Market prices of energy fuels have moved up sharply and there is wide uncertainty concerning probable future price levels. For natural gas, the shortage of supply has become increasingly severe. Estimated curtailments of firm service by interstate pipelines for the winter period November 1974 - March 1975 are double the curtailments during the comparable 1973-1974 period. Prices for new intrastate natural gas sales have moved up sharply. For interstate sales, which are under Federal Power Commission regulation, there has been some upward movement of FPC price ceilings. FPC Opinion No. 699-H, issued December 4, 1974 in Docket No. R-389-B, established a nationwide ceiling of 51 cents per Mcf, plus state taxes, for sales initiated on and after January 1, 1973 and for renewals of expiring contracts. An FPC decision in the proceeding to establish nationwide rates for "old gas" sales is pending in FPC Docket No. R-478.

Evaluation of Policy Alternatives

Because of the current concern with energy problems, there is widespread interest in answers to what appear to be simple questions: What would be the "cost" of deregulation, in dollars? By how much would deregulation raise the consumer's gas bill? The seemingly simple questions in fact involve multi-faceted, highly complex considerations. There are no definitive answers available because uncertain judgments concerning the future must be used in any attempt to make such estimates.

With continued regulation under existing FPC regulatory policy, it may be anticipated that average field prices would be lower than under the deregulation alternative and that the volumes of gas available for use would also be lower. The question then becomes that of estimating the costs associated with filling the gap between requirements and supply and the costs associated with possible inability to balance energy supplies and requirements.

A comprehensive comparison of the policy alternatives of partial deregulation and continuation of existing regulatory controls would require estimates of a large number of uncertain parameters: the price of domestic gas supplies with deregulation and with continued regulation; the volumes which will be delivered under new contracts with partial deregulation and with continued regulation; the quantities of supplemental gas supplies and the prices and availability of such supplies under the two policy alternatives; pipeline transportation costs under the load factors resulting from the two alternatives; requirements for other energy fuels to meet deficiencies of gas supply under the two policy options; costs of gas-burning equipment as compared with equipment for other fuels and cost of conversion from gas to other fuels if required; security of energy supplies and costs associated with possible disruption of supplies to end-users; balance of payments considerations; and environmental and other factors.

Such a comparative evaluation of the policy alternatives is beyond the scope of this report. This report focuses on two more limited questions: (1) the dollar impact of partial deregulation on the cost of gas supplies under pre-1975 interstate contracts and (2) the estimated change, from the present levels, in gas costs to the residential consumer on the assumption of deregulation. The study is limited to the interstate market for natural gas, the portion of the market which is now subject to FPC regulatory controls. No attempt is made here to consider the repercussions, if any, of partial deregulation on intrastate prices.

The more restricted nature of the inquiry does not eliminate the need for estimates. However, it sharply reduces the number and types of estimates which are required. The resulting impact estimates should be considered to show the cost of deregulation without any consideration of the offsetting benefits.

The foundation for the estimates is a detailed study of the contract prices, volumes, contract provisions, expiration dates, and FPC price ceilings for interstate gas sales under existing contracts. The interstate contract study is described at pages 9-10 and in Appendix A.

Dollar Impact of Deregulation

Deregulation of expiring contracts on renewal would have a cost impact of $33 - $63 million during 1975 assuming an unregulated market price in the range of $1.25 - $1.75 per Mcf. By 1979, with additional contracts expiring, this impact would have increased to $0.91 - $1.6 billion annually. The cost impact of deregulation of expiring contracts is gradual because most of the gas supply under contracts now in force was sold under long-term contracts for a term of 20 years. Thus, it is estimated that as of January 1, 1980, only 18 percent of the total volume under agreements entered into prior to January 1, 1975 would be covered by contracts which had expired by their own terms.

The increase in cost for all supplies under contracts now in force, including gas sold under limited-term and emergency sales as well as expiring conventional contracts, is estimated at $93 - $183 million in the first year, increasing to reach $1.50 - $2.83 billion annually by 1979.

The estimates of dollar impact of deregulation of existing sales (Part III) depend on the information provided by the contract price study and on estimates of the price at which expiring contracts (which would be deregulated) would be renewed. The impact estimates are derived as the difference between the costs under partial deregulation and the costs at the existing Federal Power Commission price ceilings. To the extent that these price ceilings may reasonably be expected to increase in the future in the event of continued regulation, the impact estimates are overstated. The estimates of cost impact are made on three alternative bases, corresponding to assumed unregulated market prices of $1.25, $1.50, and $1.75 per Mcf.

The impact of deregulation of new gas sales is more difficult to project inasmuch as the volumes which would be committed to interstate sales and produced in future years with continued regulation are uncertain. For each 100 billion cubic feet of supplies (in terms of average annual volumes under new sales) which would be sold in interstate commerce with continued FPC price regulation, the cost impact is estimated at $32 - $60 million in the first year, increasing to $0.29 - $0.54 billion in the year 1979.

Increases in Field Prices

The prospective increase in gas prices in the field with partial deregulation depends on both the prices for unregulated and regulated sales and on the prospective volumes. While the volumes can be projected reliably for contracts now in force, the quantities of new gas are uncertain. The study used three alternative estimates, the "Medium" involving the assumption that total interstate deliveries will remain roughly unchanged over the next five years, the "Higher" involving a small increase in supply, and the "Lower" assuming a small year-to-year decline in total production volumes. The "deregulated" volume is projected as 6 percent of total interstate gas by January 1, 1976, 23 percent by January 1, 1978, and 43 percent by January 1, 1980, using the "Medium" estimate of new gas supplies.

The three alternative projections of new-gas volumes, in conjunction with the three assumptions of unregulated market price result in nine estimates of prospective field prices. Although the estimates were not derived from formal projections of elasticity, each of the nine estimates in effect corresponds to an implicit assumption concerning the price-elasticity of gas supply.

The increase in field prices in the first full year, under these assumptions, is 5-11 cents per Mcf. By January 1, 1980, the projected field price increases to 69-100 cents per Mcf, compared with the current average of 31 cents per Mcf. Using the estimate that the unregulated market price will average $1.50 per Mcf, the estimates of future field prices are as follows:

Projected Field Prices
(Cents per Mcf)

	"Lower" New-Gas Volumes	"Medium" New-Gas Volumes	"Higher" New-Gas Volumes
1/1/76	37.4¢	38.9¢	40.4¢
1/1/77	46.6	49.4	52.1
1/1/78	56.2	60.3	63.9
1/1/79	66.6	71.8	75.9
1/1/80	78.6	84.0	88.6

Costs to Residential Consumers

The price of gas in the field accounted in 1974 for about 19 percent of the price paid by the residential consumer, with the balance representing the costs of transportation and distribution. At the existing (January 1, 1975) levels of field prices for natural gas and of pipeline transportation costs, the cost of natural gas to the residential consumer, on an average nationwide basis, is $1.50 per Mcf. With annual consumption of 120 Mcf per customer (approximately the 1974 level), the annual average cost of residential gas service is $180.00. Estimates of future cost increases were derived using the assumption that increases in field prices per Mcf of gas would be passed on, cent for cent, to the prices paid by consumers.

The increase in costs to the residential consumer (from January 1, 1975) as a result of rising field prices is estimated in the range of $6 - $13 after one year, increasing to $45 - $83 annually after five years. The year-to-year increases average 4.6 to 7.9 percent annually, depending on the assumptions for market price and volumes.

Assuming a market price in the field of $1.50 per Mcf (for new sales and expiring contracts) and the "Medium" estimate of new-contract volumes, increases in consumer cost attributable to higher field prices are estimated as follows:

	Annual Consumer Cost	Year-to-Year Increase	Percent Increase
1/1/76	$189.24	$ 9.24	5.1%
1/1/77	201.84	12.60	6.7
1/1/78	214.92	13.08	6.5
1/1/79	228.36	13.44	6.3
1/1/80	243.36	15.00	6.6

As noted above, the estimates of increase in costs to the residential consumer with partial deregulation are expressed in terms of the changes in prices and costs from the existing levels. Consequently, they show the range of probable results only under the policy alternative of partial deregulation. These cost increases must be evaluated in light of studies and judgments of the costs which will be incurred with continued regulation under existing regulatory policies.

II. Procedures Used in the Study

The Administration's deregulation proposals would remove regulatory controls from new sales in interstate commerce, gas sold from new wells, and sales continued in interstate commerce after the expiration of a contract existing at the date of enactment of the legislation. For the purpose of this study the "date of enactment" is assumed to be January 1, 1975, so that the impact estimates presented here take account of all existing interstate contracts terminating after January 1, 1975 and of projected new-gas deliveries after that date.

A. Study of Interstate Gas Sales Contracts

The starting point for the present analysis is a detailed study of the pricing provisions, volumes, and expiration dates of interstate gas sales contracts. The study covered 1,376 larger-volume sales with a 1972 delivery volume of 9.3 billion cubic feet; the contracts included represent 70 percent of the total volume sold by producers to interstate pipelines in 1972. In addition, large-volume sales initiated after 1972 (covering both new contracts and gas from "new wells" under existing contracts) were included, the sample sales representing 75 percent of the volume for the post-1972 commitments. The data derived from the sample of large-volume contracts were expanded to obtain the estimates presented here for all interstate sales. It is believed that the sample data, as expanded to totals, reliably represent the prices and volumes for all interstate sales under pre-1975 contracts.

The study projected, for each sale, the prices payable to 1980 in accordance with existing FPC rate ceilings, taking into account the provisions of each contract with respect to price, quality, conditions of delivery, and Btu content. In projecting the prices payable under continued FPC rate ceilings, the provisions of FPC Opinion No. 699-H, issued December 4, 1974 in Docket No. R-389-B, were used as the ceiling prices for sales qualifying for rate treatment under that Opinion: gas from wells commenced on or after January 1, 1973; gas first sold in interstate commerce on or after January 1, 1973; and gas sold under certain contracts superseding prior contracts which expired by their own terms. The rate ceilings for other sales are pending in FPC Docket No. R-478. Inasmuch as the FPC has not yet issued its Opinion in that proceeding, the "FPC rates" used in this study are those recommended by the FPC Staff in that proceeding.[1/]

The contract study also projected the volume of gas to be delivered under each contract, taking account of the volumetric declines which will occur in the future and using the gas "vintage" as a basis for the projection. Finally, the study identified the expiration dates of the contracts and provided summaries of the volumes for such expiring contracts. Details of the procedures followed in the contract study are shown in Appendix A.

[1/] For sales certificated under the optional pricing procedure (Order No. 455), the prices used were those authorized by the FPC for the given sales; similarly, for certain sales for which the FPC has issued orders granting special relief, the prices applicable for the given sale were employed.

B. Estimates of Unregulated Market Prices

The study of interstate gas sales contracts provides a factual basis for estimating the prospective prices for existing sales under continued FPC regulation as well as the volumes of gas under contracts scheduled to expire by their own terms which would be freed from regulatory control. In carrying through the impact estimates, it is also necessary to make estimates, on a less solid foundation, of the market prices which would be negotiated with partial deregulation and of the gas deliveries which will be made under new commitments to the interstate market.

We have assumed that unregulated market prices (for new sales or renewals of expiring contracts) would be in the range of $1.25 to $1.75 per Mcf and have made alternative computations at $1.25, $1.50, and $1.75. The price of $1.25 per Mcf used at the bottom of the range is substantially higher than the prices suggested by the Project Independence model. The $1.50 estimate corresponds generally to the range of "commodity value" of gas supplies at the present time. The upper estimate of $1.75 is included in view of scattered press reports on intrastate contracts negotiated at prices in that general range. However, information concerning the level of new-contract prices in the intrastate market is very sparse and the average level of such prices is probably substantially lower than the prices for those sales which tend to be reported in the press.

The estimated market price under each assumption is maintained at the same level, in constant dollars, to 1980. There is little basis for a projection of year-to-year price movements. Most long-term gas sales contracts do provide for price escalations over the contract term so that some increase in prices might be anticipated over time. On the other hand, some analyses suggest that the unregulated market price might tend to decline over time as larger volumes of new supplies were developed. A major consideration is the future level of prices of alternative fuel supplies. In light of the extraordinary uncertainty regarding future prices of foreign oil and in light of the uncertainties concerning Congressional action on the Administration's energy proposals, there is no basis at this time for a projection of year-to-year price changes.

C. Estimates of New-Gas Volumes

In order to estimate the average field price for interstate gas for future years on the assumption of partial deregulation, it is also necessary to make assumptions concerning the volumes which will be delivered under sales commenced after the effective date of the legislation and from new wells commenced after that date. No distinction is made here between new contracts and deliveries from new wells.

Various studies, each on the basis of different assumptions, make estimates of possible production levels for 1980 varying from 18 to 36 trillion cubic feet, compared with the current (1973) level of 22.5 trillion cubic feet. Project Independence estimated the 1980 production possibilities in a range from 16.8 trillion (representing an average annual decline of 4.1 percent from 1973) to 22.7 trillion (virtually no change from 1973 production levels). The Federal Power Commission Staff projects productive capability as of 1980 in the range from about 13.8 trillion cubic feet per year, representing an average annual decline of 6.7 percent, to about 20 trillion cubic feet, corresponding to an average decline of 1.7 percent annually. (A Realistic View of U. S. Natural Gas Supply, December 1974) The alternative projections show even a broader range for the year 1985.

The production projections cited above refer to total natural gas (interstate and intrastate) while, for the purpose of the present study, only the interstate natural gas volumes are considered. We have employed, for the purpose of the computations, three alternative sets of production volumes. The "Medium" estimate involves the assumption that new-gas volumes would be sufficient to maintain interstate production at approximately the 1973-1974 production levels through 1979. This estimate is consistent with the upper limit of the Project Independence projection for total production. "New" gas volumes could reach these levels with average annual reserves additions amounting to 17 trillion cubic feet, approximately 9 percent below the average during 1960-1967 but nearly 80 percent higher than the industry average for the years 1968-1973. The production volumes also assume that the interstate market would obtain a share of total new reserves equivalent to its share of production, or about 63 percent of the total. In other words, assuming deregulation of new gas sales, there would be no reason for sellers to favor intrastate buyers over interstate buyers and the interstate market would thus obtain a proportionate share of total new supply. Finally, it is assumed that production volumes in the initial years would be at high levels, amounting to 7.5 percent of the newly-committed reserves annually.

In light of the uncertainty concerning the size of the undiscovered natural gas resource base, we have made alternative sets of computations. The "Higher" estimate is 25 percent above and the "Lower" estimate of new-gas production volumes is 25 percent below the "Medium" estimate. The "Higher" estimate would involve annual industry-wide reserve additions of approximately 21 trillion cubic feet annually. New-gas volumes of this magnitude would permit a modest increase in the production volumes. The "Lower" estimate of new-gas volumes would require average annual industry-wide reserve additions of approximately 12.7 trillion cubic feet. Using the "Lower" estimate, the total interstate volume declines by about one trillion cubic feet over the next five years. The projected volumes are shown in Table 7.

The use of a range of estimates for the unregulated market price and the use of alternative estimates of new-gas volumes results in nine alternative estimates of the prospective changes in field prices and in consumer costs.

III. Dollar Impact of Deregulation

A. Expiring Contracts

In estimating the impact of deregulation of contracts on their expiration dates, it is necessary to take account only of those existing sales agreements which will expire by their own terms after the effective date of the deregulation legislation. For the purpose of this study, the "effective date" was assumed to be January 1, 1975, so that consideration is given to all contracts scheduled to expire on or after that date. Contracts which have expired in the past several years and which have already been renegotiated are not included in the impact estimates inasmuch as it is our understanding that such sales would not fall within the scope of the proposed legislation. Similarly, sales contracts which were originally scheduled to expire after January 1, 1975 but which have already been replaced with renegotiated contracts would not qualify for deregulation, according to our understanding, until such time as the existing (renegotiated) contracts expire by their own terms.

The contracts scheduled to expire by their own terms during the next five years account for a relatively small part of the total interstate volume. By year of expiration, such contracts account for the following volumes and proportions of the total interstate sales volume reported for 1972: 1/

1/ The volumes shown include sales initiated during the years 1973 and 1974. For such sales, the estimated annual volumes are used both for the contracts scheduled to expire and for the total.

Contracts Expiring Each Year as Percent of 1972 Volume

Contracts Expiring In:	1972 Volume (Bcf)	Percent of Total 1972 Volume
1975	140.7	0.9%
1976	508.6	3.4
1977	576.0	3.8
1978	782.5	5.2
1979	1,130.2	7.5
Total 1975-1979	3,138.0	20.8

Detail on the volume of contracts scheduled to expire, by area and year, is presented in Table 1.

The table above was derived from the 1972 volumes of the expiring contracts in relation to the 1972 volume for all interstate contracts. However, deliveries will decline in future years, so that the past (1972) volumes for contracts expiring in, for example, 1979, are larger than the volumes which will be delivered in 1979 under those contracts. Taking account of the prospective volumetric declines both for expiring contracts and other sales,[1] the contracts reaching termination prior to each date would account for somewhat smaller percentages of volume under all sales initiated prior to January 1, 1975. The percentages shown below are cumulative volumes for all contracts expiring after January 1, 1975 and refer to the immediately preceding year. For example, the volumes shown as of January 1, 1980 represent the projected 1979 volumes for all contracts terminating after January 1, 1975 and prior to January 1, 1980:

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[1] The impact estimates presented below do not take account of the fact that the deliverability under existing contracts would be affected by the respective prices which could be realized under continued regulation and deregulation.

Cumulative Expired Contracts as Percent of 1972 Volume

	Expiring Contracts (Bcf)	Percent of Total Volume
As of 1/1/76	109.2	0.9%
1/1/77	470.9	4.0
1/1/78	791.4	7.3
1/1/79	1,170.5	11.6
1/1/80	1,721.5	18.4

The information with respect to contract expirations is from Table 2.

The Federal Power Commission price ceiling for new gas and for renewals of expiring contracts as of January 1, 1975 is 51 cents per Mcf, plus state taxes and Btu adjustment (Opinion No. 699-H). For other sales, the applicable price ceiling is pending in Docket No. R-478. The FPC Staff has recommended a nationwide ceiling of 24.5 cents per Mcf, plus state taxes and Btu adjustment.

In estimating the dollar impact of deregulation, it is assumed in this study that with deregulation contracts which expire will be renegotiated at the unregulated market price level, estimated at the alternative figures of $1.25, $1.50, and $1.75 per Mcf. With continued regulation, the estimates assume that the contracts would be renegotiated at the applicable ceiling rates established by FPC Opinion No. 699-H; the average, including state taxes and Btu and other adjustments, varies between 60 and 62 cents per Mcf over the period to January 1, 1980 for the expiring contracts. The increment in price, assuming deregulation, thus, is the difference between the price which would be payable at the unregulated market level and the average price which would be payable for such sales under continued FPC regulation. In deriving the impact estimate, it is assumed that the contract expirations are spread evenly through the year. The resulting impact estimates, in billions of dollars, are as follows for the alternative assumptions concerning market price:

	Impact (Billion $) With: Market Price per Mcf		
	$1.25	$1.50	$1.75
1975	$ .033	$ .049	$ .063
1976	.189	.261	.334
1977	.404	.562	.720
1978	.628	.873	1.118
1979	.911	1.272	1.634

The details of the computations are shown in Table 3.

The impact of deregulation of expiring contracts would thus be quite small in the first year, in the range of $33 to $63 million, and would increase to reach $0.91 - $1.63 billion annually in the fifth year. The cumulative totals, over a five-year period, would be in the range of $2.2 - $3.9 billion.

Although the estimates assume that all expiring contracts would be renegotiated at the applicable FPC ceiling in the event of continued regulation or at the market price for new supplies in the deregulation case, it is recognized that some contracts may not be renegotiated at the highest prices in either situation. This factor results, if anything, in an overestimate of the impact estimates shown here.1/

1/ For example, if the price for expiring contracts on renewal changes from 30 cents to 60 cents per Mcf with continued regulation and from 30 cents to $1.50 with deregulation, the impact estimates shown above would be virtually unchanged if 25 percent of all sales were not renegotiated in the continued regulation case, compared with 5 percent not renegotiated in the deregulation alternative.

B. Other Existing Interstate Contracts

Aside from expiring contracts, it does not appear that the pending deregulation proposals would produce any significant cost impact with respect to gas now moving in interstate commerce. In particular, there is no reason to assume that deregulation of contracts on their expiration would have any effect on FPC regulatory policy with respect to the contracts which continue to be subject to regulatory controls (memorandum dated October 1, 1974, from Frank C. Allen, Chief, Bureau of Natural Gas, FPC, to the Commission, forwarded to Senator Buckley October 3, 1974 by John N. Nassikas, Chairman of the FPC).

Many interstate gas sales contracts include contractual provisions permitting upward adjustment of prices from the levels initially specified in the contracts. Such contract provisions include redetermination or renegotiation clauses, area rate clauses, and, for contracts executed prior to 1962, favored-nation provisions. All such contractual agreements operate within the limits of FPC regulatory ceilings. Such clauses may provide a contractual basis for an increase in the price, but the price actually paid will be limited by the FPC price ceilings. "Deregulation" clauses, which have been included in some interstate sales contracts in recent years, would, of course, become effective only if the sales in question were freed from regulatory controls by legislation. It is our understanding that contractual provisions of the types described would have no bearing on the dollar impact of the Administration's deregulation proposal.

A question arises concerning "limited-term" sales for a period of one to three years with pre-granted abandonment authorization and "emergency" sales for a period of 60 days. The annual volume of supplies under "limited-term" contracts in the last 12 months for which data are available (July 1, 1973 - June 30, 1974) was 166 billion cubic feet but, more recently, the volumes of such new sales has declined to about 30 percent of the prior volume, or to about 50 billion cubic feet on an annual basis. The recent volume of gas sold under "emergency" sales, on an annual basis, is about 110 billion cubic feet. Thus, judging from the commitments in recent months, the total gas volume for such sales at the present time is about 160 billion cubic feet annually.

However, there is no assurance that comparable volumes of such supplies will be available to the interstate market under the assumption of continued regulation. The natural gas being delivered under such arrangements is not "committed" to the interstate market except for the short duration of the contract. Under FPC regulation, the sellers are free to terminate deliveries at the contract expiration date and to sell the supplies in question in the unregulated intrastate market. Inasmuch as only a minor proportion of such sales are from the Federal offshore area, assuming continuation of FPC regulation at existing prices, the sellers of such supplies would have the opportunity to dispose of the gas in the unregulated intrastate market in the future if higher prices can be obtained in that market. Thus, it is uncertain whether partial deregulation would involve any appreciable cost impact for this type of sale.

The prices for such supplies are not subject to the FPC price ceilings applicable for other sales, except with respect to sales from the offshore Federal domain. The actual prices have moved up over time. Currently, the average price for such sales is approximately 70-75 cents per Mcf. If it is assumed that with a continuation of existing regulatory controls commitments of this type would average 120 billion cubic feet annually (25 percent below the recent commitments) at the same prices and that the price would move up to the $1.25 - $1.75 range with deregulation, the impact is in the range of $60 million to $120 million annually (Table 4).

C. All Existing Sales

Combining the figures for renewals of expiring conventional contracts and for limited-term and emergency sales, the total impact estimate for existing sales is $93 to $183 million in the first year, increasing to reach $1.51 to $2.83 billion annually in the fifth year. The cumulative totals, over a five-year period, would be in the range of $2.5 - $4.5 billion.

The estimates of dollar impact presented above were derived on the assumption that FPC price ceilings for new gas and renewals of expiring contracts would conform with the levels established in Opinion No. 699-H through January 1, 1980. In fact, when Opinion No. 699-H was issued in December 1974, the FPC determined that it would institute a proceeding to review the rate ceilings which would be applicable for the period January 1, 1975 - December 31, 1976 (Docket No. RM75-14, Order Instituting Proceeding, issued December 4, 1974). It may be anticipated that such periodic review proceedings will culminate in increases in the prices permitted under regulation. Thus, the impact estimates presented above are overstated by an indeterminate amount corresponding to the prospective increases in FPC price ceilings over time.

D. New Gas Sales

The estimates of price impact for expiring contracts are based on reliable data for the volumes of natural gas under sales contracts which are scheduled to expire in future years. The estimates of unregulated market price involve uncertainty, but the use of a range provides a reasonable indication of the probable magnitudes. With respect to new gas sales, the volumes to be delivered in future years with continued regulation cannot be estimated reliably (in contrast to the volumes for renewals of expiring contracts).

The estimate of impact of deregulation on cost of new interstate gas properly should be limited to the increase in price for such supplies as would be committed to the interstate market with continued FPC price regulation. No specific estimates are presented here inasmuch as the prospective volumes are highly uncertain. New-gas commitments averaged 560 billion cubic feet per year during 1969-1972, in terms of annual delivery volumes. Thereafter, intrastate prices increased sharply and commitments to the interstate market under new contracts declined substantially. In 1973 and 1974, new-contract commitments averaged less than 200 billion cubic feet per year (in terms of annual delivery volumes).[1]

Estimates concerning future new-gas volumes with continued regulation vary widely. For example, estimates made by the Staff of the Federal Power Commission in a December 1974 study paint a very pessimistic picture of the outlook assuming a continuation of past trends.[2] The estimate in that report based on a continuation of trends over the past six years implies interstate reserves additions of 3.1 trillion cubic feet annually, equivalent to annual delivery volumes of roughly 200 billion cubic feet under the contracts negotiated in any one year. On the other hand, a March 1974 FPC Staff study[3] makes very optimistic supply assumptions concerning interstate production volumes in the "base case" of continued regulation. These estimates show, alternatively, production remaining unchanged between 1975 and 1980 (equivalent to new-contract volumes of about 800 billion cubic feet annually) and increasing by 1.8 trillion cubic feet over the five years (equivalent to new-contract volumes of 1,200 billion cubic feet annually). Such annual average new-gas volumes would be equivalent to interstate reserves additions averaging 11-16 trillion cubic feet annually.

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[1] The filings made with the Federal Power Commission show a large volume of gas from "new wells" for the year 1973, but it is uncertain whether this volume represents a one-time response to the price ceilings anticipated for post-1973 gas on the outcome of Docket No. R-389-B. Moreover, the Commission's order issued March 7, 1975 appears to restrict the definition of "new wells" to wells in reservoirs discovered on or after January 1, 1973; this restriction may limit supplies from new wells in the event of continued regulation.

[2] A Realistic View of U. S. Natural Gas Supply, Staff Report, Bureau of Natural Gas, December 1974.

[3] Summary of the Preliminary Staff Evaluation of the Costs and Benefits of Natural Gas Deregulation, attached to the Statement of John N. Nassikas, Chairman, Federal Power Commission before the Subcommittee on Energy and Power, Committee on Interstate and Foreign Commerce, U. S. House of Representatives, March 17, 1975.

Although we do not project the new-gas volumes with continued regulation, an indication of possible impact can be provided. The ceiling price for new interstate sales, in accordance with Opinion No. 699-H is 51 cents per Mcf, plus state taxes and Btu adjustment. Inclusion of state taxes for new gas other than from the Federal offshore area would raise the average regulated price for all new supplies to about 55-60 cents per Mcf. Consequently, assuming an unregulated market price in the range of $1.25 - $1.75 per Mcf, for each 100 billion cubic feet of supplies (in terms of annual volumes under new sales), the cost impact in the first year would be $32 - $60 million. In the fifth year, with the higher volumes of post-1974 gas, the dollar impact would be $0.29 - $0.54 billion for each 100 billion cubic feet of average annual new-gas delivery volumes.[1]

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[1] The computations assume that commitments would be made evenly over they year, so that deliveries under post-1974 contracts in the year 1975 would represent half the average annual commitment, while deliveries in 1979 would represent four-and-a-half times the average annual new-contract volume.

IV. Prospective Field Prices for Natural Gas Under Partial Deregulation

The preceding section presented estimates of the dollar impact of partial deregulation in terms of the additional revenues for natural gas sales under deregulation as compared with continued regulation. This section, as a preliminary step in the estimation of prospective change in price to the residential consumer, focuses on the prospective change in field prices for natural gas in the interstate market under the condition of deregulation.

The average field price for interstate sales in future years depends on the prospective volumes and prices for three types of sales: (1) "old" gas which would continue to be sold under Federal Power Commission regulation; (2) renewals of contracts expiring after the effective date of the legislation; and (3) new gas commitments to the interstate market subsequent to the effective date of the legislation.

The volumes of "old" gas and of renewals of expiring contracts were derived from the detailed contract study (Table 2). The estimated volume of new gas commitments was projected on three alternative bases. The "Medium" estimate assumes new commitments averaging 800 billion cubic feet annually, consistent with average annual industry-wide reserve additions of about 17 trillion cubic feet. The "Higher" estimate assumes new-gas commitments of 1,000 billion cubic feet per year and the "Lower" estimate assumes new-gas commitments to the interstate market averaging 600 billion cubic feet annually (see pages 12-14).

For all three estimates, we have used some build-up in annual new-contract volumes. Thus, for the "Medium" estimate, the annual volumes under new contracts in each year increase from 700 billion cubic feet in the first year to 900 billion in the fifth year. In the fifth year, the total delivery volume for contracts initiated after January 1, 1975 is 4,000 billion cubic feet (Table 7).

The proportion of total interstate gas which would be deregulated builds up only moderately over time. As of January 1, 1980, using the "Medium" estimate of new-gas volumes, it is projected that 57 percent of the interstate volume would be subject to FPC regulation. As indicated previously, the volume of expiring contracts is a relatively small part of the total projected volume for all sales. The volumes projected for sales initiated after January 1, 1975, while substantially larger, still increase only gradually.

Using the "Medium" estimate of new-gas volumes, the following proportions of total interstate volume would be deregulated in accordance with the Administration's proposal (Table 7):

	Expiring Contracts[1]	New Sales	Total Deregulated
By 1/1/76	0.8%	5.3%	6.1%
1/1/77	3.6	11.0	14.6
1/1/78	6.0	17.1	23.2
1/1/79	8.8	23.8	32.6
1/1/80	12.9	29.9	42.8

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[1] The percentages shown here are smaller than the figures shown at page 17, because page 17 shows the volume of expiring contracts in relation to sales initiated prior to January 1, 1975 while the figures here show the volume of expiring contracts in relation to all sales, under both existing and prospective contracts.

The future price for the "old" gas deliveries was derived from the contract-by-contract analysis, using the existing FPC price ceilings applicable to each contract at each future date. For renewals of expiring contracts and for new sales, we have used the estimated "market price" and thus show alternative projections corresponding to assumed market prices of $1.25, $1.50, and $1.75 per Mcf.

As of January 1, 1975, the average field price for all interstate sales was 31.2 cents per Mcf.[1/] The projected field prices for the future, under the assumptions noted, are as follows using the estimate that unregulated market price will average $1.50 per Mcf:

	"Lower" New-Gas Additions	"Medium" New-Gas Additions	"Higher" New-Gas Additions
	(Cents per Mcf)		
1/1/76	37.4¢	38.9¢	40.4¢
1/1/77	46.6	49.4	52.1
1/1/78	56.2	60.3	63.9
1/1/79	66.6	71.8	75.9
1/1/80	78.6	84.0	88.6

Table 8 shows the derivation of these estimates, together with the field price estimates corresponding to estimated market prices of $1.25 and $1.75 per Mcf. The alternative estimates result in projected field prices of 69-100 cents per Mcf as of January 1, 1980.

The prospective field price, assuming the $1.50 market price estimate and the "Medium" estimate of new gas supply, rises by about 7 cents per Mcf in the first year following deregulation and by an

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[1/] This average reflects the upward adjustments in price resulting from rate-increase filings in accordance with FPC Opinion No. 699-H and also the anticipated upward adjustment in price which will result from the Opinion to be issued in FPC Docket No. R-478.

average of 11 cents per year thereafter. The rise in field prices is spread over a substantial period of years because the new-gas volumes, at higher prices, build up only gradually and because renewals of expiring contracts also occur gradually over a period of years.

Future field prices will, of course, increase even in the event of continued FPC regulation of all interstate sales. FPC price ceilings for renewal contracts are about 60 cents per Mcf on an average nationwide basis, compared with an average regulated price of about 31 cents per Mcf applicable for "old" sales. The FPC price ceiling for new sales (51 cents as of January 1, 1975, plus state taxes and Btu adjustment) would vary from about 53 cents in the Federal offshore area to about 62 cents for onshore Louisiana (including Btu adjustment). Thus, as the gas volumes flowing under new and renewal contracts increase in relative importance, the regulated price for all sales would rise. The existing FPC price ceilings for new and renewal sales are scheduled to escalate by one cent each January 1. More important, these price ceilings are subject to periodic review and revision which may be expected to result in increases in the applicable ceiling prices as a result of higher costs of finding and developing gas supplies. [Table 5 shows the projected regulated price for sales under contracts initiated prior to January 1, 1975, using the existing FPC rate ceilings. Table 6 shows the projected field price for the pre-1975 sales on the assumption of partial deregulation.]

The estimates of new-gas volumes used here are not intended to show in any definitive way the expected quantities of natural gas which will be commited to the interstate market in the event of partial deregulation. The estimates are based on the magnitudes suggested by the studies made by others and were not derived from any independent study made for the purpose of this report. It should be emphasized that none of the studies designed to yield estimates of natural gas supply additions under alternative assumptions concerning price and other incentives yield results which may be regarded as definitive. The supply of natural gas is clearly responsive to price but the elasticity of supply cannot be quantified.

Because the field-price estimates presented here for all sales are expressed in terms of the increase in field price from the existing levels as of January 1, 1975 (rather than in terms of a comparison of prices under deregulation and continued regulation), the results appear on the surface to be anomalous. The estimates of field prices for future years are sensitive to the estimates of the quantity of gas which will be produced under contracts to be executed in the future. Inasmuch as the market price for such new gas will be substantially higher than the average price for gas to be delivered under pre-1975 contracts, the higher the estimate of "new" gas supplies, the greater is the "rolled-in" price of all supplies and the greater the apparent increase in cost from existing levels. However, a larger rather than a smaller volume of new supplies would in fact benefit the consumer by reducing the need for higher-priced supplemental supplies, the dependence on alternatives to natural gas, and the cost of converting from gas to other energy fuels.

The projections of field prices and increases in consumer cost made in this report extend to January 1, 1980. Beyond 1980, the volumes producible from existing reserves will decline sharply. Thus, it has been estimated that, with limited reserve additions at the level of the last six years, production would decline from the peak of 14.2 trillion cubic feet in 1972 to 6.8 trillion cubic feet in 1985.1/ The availability of gas supplies in the longer term thus depends almost entirely on the quantities of gas found and developed and committed to the interstate market in the future.

1/ Federal Power Commission, Bureau of Natural Gas, A Realistic View of U. S. Natural Gas Supply, Staff Report, December 1974.

V. Prospective Costs to the Residential Consumer Under Partial Deregulation

The price of gas in the field accounted in 1974 for about 19 percent of the price paid by the residential consumer, the balance representing the cost of pipeline transportation and of distribution by the gas utilities. The average field price for the year was 26 cents per Mcf while the cost to the residential consumer was $1.39 per million Btu [1] (approximately equivalent to one Mcf). In accordance with the Federal Power Commission proceedings to determine revised nationwide price ceilings for both "new" gas (Docket No. R-389-B) and "old" gas (Docket No. R-478), the field price will increase by about 5 cents per Mcf above the average which was paid for the year 1974. Transportation and distribution costs are also increasing as a result of price inflation and gas curtailments. As an example, the estimated pipeline transportation cost (derived as the difference between the price received by pipelines for sales for resale and the price paid by the pipelines for their gas supplies) was about 25 cents per Mcf for December 1973 but had increased to 35 cents per Mcf by November 1974. The estimated transportation cost for November 1974 was about 5 cents higher than the average for the entire year.[2]

At existing levels of field prices and transportation costs, we estimate the average cost to the residential consumer at a conservative $1.50 per Mcf, up 11 cents from the 1974 average of $1.39. This is a minimum estimate which does not make allowance for any rise in utility distribution costs during the year 1974.

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[1] American Gas Association

[2] FPC News Releases

Average consumption per residential customer varies from year to year, depending on the weather, number of gas appliances, and similar factors. In 1974, average consumption amounted to 121.4 Mcf per customer, as compared with 124.5 Mcf during calendar year 1973 and approximately 130 Mcf during 1970-1972.[1/] In projecting the future changes in cost to the residential consumer, we use an estimate of future annual consumption per customer amounting to 120 Mcf, or at about the same level as in 1974. The prospective increase in the cost of residential gas service will probably have some restraining influence on the quantity of gas consumption per customer. On the other hand, the consumption data for the years 1973 and 1974 reflect unusually mild winters. The estimate of 120 Mcf per customer takes account both of expected conservation by gas users and of more normal winter temperatures.

Using the estimated gas cost of $1.50 per Mcf as the existing level of cost to residential customers, together with annual consumption of 120 Mcf, we derive an estimated annual expenditure of $180 per residential gas customer, at existing levels of field prices and transportation costs. This is the base from which the future increases in residential consumer cost are measured in this report.

In estimating the prospective changes in consumer cost, it is assumed that increases in field prices per Mcf of natural gas will flow through on a cent-for-cent basis to the prices paid by residential

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1/ American Gas Association

consumers (Table 9). Some minor adjustment to this assumption might be appropriate, mainly to take account of gas used for pipeline fuel, but the amount would not be significant. It is also assumed that all residential customers are served by "interstate" gas, that is, gas now subject to FPC regulation at the point of sale in the field. In fact, some residential customers in the gas-producing states receive gas which is purchased and transmitted by intrastate pipelines.

The projected increases in field prices (Tables 8, 9), together with the estimate of annual consumption of 120 Mcf per residential customer, provides the basis for the range of estimates of annual cost to the residential consumer (Tables 10-12). The increase in costs to the residential consumer (from January 1, 1975) as a result of rising field prices is estimated in the range of $6 - $13 after the first full year, increasing to $45 - $83 annually after five full years.1/

Assuming a market price in the field of $1.50 per Mcf (for new sales and expiring contracts) and the "Medium" estimate of new-contract volumes, increases in consumer cost attributable to higher field prices are estimated as follows:

	Annual Consumer Cost	Year-to-Year Increase	Percent Increase
1/1/76	$189.24	$ 9.24	5.1%
1/1/77	201.84	12.60	6.7
1/1/78	214.92	13.08	6.5
1/1/79	228.36	13.44	6.3
1/1/80	243.36	15.00	6.6

1/ The estimated cost increases are shown as of January 1, each year 1976-1980, for the reason that the data on prices for regulated sales are available on that basis. The cost increase to the consumer in any year would be approximately (but not precisely) the average of the estimates shown in the tables for January 1 of successive years.

The increase in costs during the first year, under the stated assumptions, would be about 5 percent, compared with the "base" figure of annual expenditures of $180 per residential customer. Subsequently, through January 1, 1980, the year-to-year cost increases are in the range of 6.3 to 6.7 percent annually. As of January 1, 1980, the cumulative increase in annual costs (from the base level of $180 per year) is $63, resulting in an annual gas bill of $243, 35 percent above the base level.

A lower field market price would, of course, reduce the consumer cost and a higher field price would be accompanied by larger increases in consumer gas cost. Tables 10 and 11 shows the estimates of consumer costs derived for alternative estimates of market price and new-gas volumes. Using the "Medium" new-gas volumes and an unregulated field market price of $1.25 per Mcf, the near-term increase in annual cost is $7.44 and the increase after five years is $50.40, about 28 percent above the base levels. At a $1.75 unregulated field price, the initial cost increase to the residential consumer is estimated as $11 annually and the cumulative increase over five years is $76, 42 percent above the base level.

With respect to the alternative volume estimates, as discussed above (page 29), the "Higher" estimate of new-gas volumes results in a larger increase in the estimate of consumer cost (and vice versa), inasmuch as the cost increases projected here refer only to changes attributable to increases in field prices for domestic natural gas supplies from the existing levels.

The projected increases in consumer cost described above show prospective changes in residential consumer costs attributable to increases in field prices from the existing levels, on the assumption of partial deregulation of natural gas prices. With continued regulation under existing FPC regulatory policy, field prices would also increase, though to a lesser extent than under the deregulation alternative, and the gas volumes would be lower. The policy question then becomes that of estimating the costs of alternative energy supplies required to fill the gap between requirements and supply and the costs of possible inability to balance energy supplies and requirements.

Table 1

1972 VOLUMES FOR INTERSTATE GAS SALES CONTRACTS WITH EXPIRATION DATES DURING 1975-1979

(Billions of Cubic Feet at 14.65 Psia)

Area	Total Volume, All Sales, 1972	Volumes of Contracts Expiring In: 1975	1976	1977	1978	1979
South Louisiana, Offshore	3,204.5	--	4.8	63.8	6.6	94.6
South Louisiana, Onshore	3,901.4	76.1	365.0	61.5	216.1	649.6
Permian Basin	2,174.3	15.1	--	156.8	141.7	194.4
Texas Gulf Coast	1,484.9	34.6	10.5	52.1	99.2	41.7
Hugoton-Anadarko	2,366.9	--	52.0	111.1	274.5	30.7
Other Southwest	1,076.7	--	--	130.7	35.8	119.2
Appalachian-Illinois	186.1	--	--	--	--	--
Rocky Mountain	740.6	14.8	76.3	--	8.6	--
Other	14.2	--	--	--	--	--
Total	15,149.6	140.7	508.6	576.0	782.5	1,130.2

Source: Study of interstate gas sales contracts on file with the FPC as of January 1, 1975. See Technical Note, Appendix A.

All volumes shown are the reported volumes for the year 1972 (as reported in the 1972 Form 301-B Reports), except that, for sales initiated after 1972, the volumes are estimated annual volumes. The figures shown in each year are the total volumes for all contracts terminating in that year. See Technical Note.

Table 2

ESTIMATED FUTURE VOLUME FOR RENEWALS OF CONTRACTS WITH EXPIRATION DATES DURING 1975-1979

Year	Annual Volume for Contracts Expiring Prior to Year-End (a)	Annual Volume, All Interstate Contracts Initiated Prior to 1/1/75 (b)	Expiring Contracts as Percent of Total (c)
	(Billions of Cubic Feet at 14.65 Psia)		
1975	109.2	12,546.1	1.27%
1976	470.9	11,693.9	4.03
1977	791.4	10,876.1	7.28
1978	1,170.5	10,095.0	11.60
1979	1,721.5	9,354.5	18.40

Source: Study of interstate gas sales contracts on file with the FPC as of January 1, 1975. See Technical Note, Appendix A.

The volumes shown are the projected volumes for each year. (See Technical Note.) Column (a) includes all contracts expiring after 1/1/75 and prior to the end of each year. For example, the volume shown in column (a) for 1977 includes the projected 1977 volume for all contracts expiring in the years 1975-1977, inclusive.

Table 3

ESTIMATED DOLLAR IMPACT OF DEREGULATION: RENEWALS OF EXPIRING CONTRACTS

	1975	1976	1977	1978	1979
1. Volume, renewals of expiring contracts (Bcf at 14.65 psia)	54.6	290.1	631.2	981.0	1,446.0
2. Estimated revenue per Mcf, continued regulation	$ .60	$ .60	$ .61	$ .61	.62
3. Additional revenue per Mcf with deregulation					
a) Market price $1.25	$ .65	$ .65	$ .64	$ .64	$ .63
b) Market price $1.50	.90	.90	.89	.89	.88
c) Market price $1.75	1.15	1.15	1.14	1.14	1.13
4. Impact of deregulation (Million $)					
a) Market price $1.25	$32.8	$188.6	$404.0	$ 627.8	$ 911.0
b) Market price $1.50	49.1	261.1	561.8	873.1	1,272.5
c) Market price $1.75	62.8	333.6	719.6	1,118.3	1,634.0

Line (1) - Averages of the volumes shown for contracts expiring prior to January 1 of each year (Table 2). It is assumed that the expiration dates are spread evenly during the year.

Line (2) - See Technical Note, Appendix A.

Table 4

ESTIMATED ANNUAL DOLLAR IMPACT OF DEREGULATION: LIMITED-TERM AND EMERGENCY SALES

	Annual Average 1975-1979
1. Volumes (Bcf at 14.65 psia)	120
2. Estimated revenue per Mcf, continued regulation	$ .75
3. Additional revenue per Mcf with deregulation	
a) Market price $1.25	$ .50
b) Market price $1.50	.75
c) Market price $1.75	1.00
4. Impact of deregulation (Million $)	
a) Market price $1.25	$ 60.0
b) Market price $1.50	90.0
c) Market price $1.75	120.0

Source: See text.

Table 5

PROJECTED FIELD PRICE FOR SALES INITIATED PRIOR TO JANUARY 1, 1975: CONTINUED REGULATION AT PRESENT CEILING PRICES

(Cents per Mcf at 14.65 Psia)

	Renewals of Contracts Expiring After 1/1/75 (a)	Other Sales (b)	Total (c)
1/1/75	--	--	31.2
1/1/76	60.1	31.7	31.9
1/1/77	60.7	32.2	33.3
1/1/78	60.5	33.2	35.2
1/1/79	61.4	34.0	37.1
1/1/80	62.8	34.5	39.7

Source: Study of interstate gas sales contracts on file with the FPC as of January 1, 1975. See Technical Note, Appendix A.

The prices shown for 1/1/75 (and subsequent years) reflect rate-increase filings in accordance with Opinion No. 699-H, issued December 4, 1974. The prices for all dates also take account of anticipated rate-increase filings in accordance with the ceilings to be established in Docket No. R-478, using the rate recommendations of FPC Staff in that proceeding.

Table 6

PROJECTED FIELD PRICES FOR INTERSTATE SALES UNDER PARTIAL DEREGULATION: DELIVERIES UNDER SALES INITIATED PRIOR TO JANUARY 1, 1975

	Market Price for Unregulated Sales:		
	$1.25	$1.50	$1.75
	(Cents per Mcf at 14.65 Psia)		
1/1/76	32.5¢	32.7¢	32.9¢
1/1/77	35.9	36.9	37.9
1/1/78	39.9	41.7	43.5
1/1/79	44.5	47.4	50.3
1/1/80	51.12	55.7	60.3

Field Price 1/1/75 = 31.2 cents per Mcf

Source: Derived using the projected volumes for regulated sales (Table 7, column (a)) and for renewals of expiring contracts (Table 7, column (b)), together with the prices for regulated sales (Table 5, column (b)) and the alternative assumed market prices for unregulated sales ($1.25, $1.50, and $1.75).

Table 7

PROJECTED VOLUMES FOR INTERSTATE SALES OF NATURAL GAS

(Billions of Cubic Feet at 14.65 Psia)

	Sales Which Continue Under FPC Regulation (a)	Deregulated Sales: Renewals of Expiring Contracts (b)	Deregulated Sales: New Contracts and New Wells (c)	Deregulated Sales: Total (d)	All Sales (e)
		A. "Lower" New-Gas Volumes			
1975	12,436.9	109.2	525.0	634.2	13,071.1
1976	11,223.0	470.9	1,087.0	1,557.9	12,780.9
1977	10,084.7	791.4	1,687.0	2,478.4	12,563.1
1978	8,924.5	1,170.5	2,325.0	3,495.5	12,420.0
1979	7,633.0	1,721.5	3,000.0	4,721.5	12,354.5
		B. "Medium" New-Gas Volumes			
1975	12,436.9	109.2	700.0	809.2	13,246.1
1976	11,223.0	470.9	1,450.0	1,920.9	13,143.9
1977	10,084.7	791.4	2,250.0	3,041.4	13,126.1
1978	8,924.5	1,170.5	3,100.0	4,270.5	13,195.0
1979	7,633.0	1,721.5	4,000.0	5,721.5	13,354.5
		C. "Higher" New-Gas Volumes			
1975	12,436.9	109.2	875.0	984.2	13,421.1
1976	11,223.0	470.9	1,812.0	2,282.9	13,505.9
1977	10,084.7	791.4	2,812.0	3,603.4	13,688.1
1978	8,924.5	1,170.5	3,875.0	5,045.5	13,970.0
1979	7,633.0	1,721.5	5,000.0	6,721.5	14,354.0

Source: Columns (a) - (b) - Study of interstate gas sales contracts on file with the FPC as of January 1, 1975.

Column (c) - See text.

Table 8

PROJECTED FIELD PRICES FOR INTERSTATE SALES UNDER PARTIAL DEREGULATION: DELIVERIES UNDER NEW AND OLD CONTRACTS

	Market Price for Unregulated Sales: $1.25	$1.50	$1.75
	(Cents per Mcf at 14.65 Psia)		
A. "Lower" New-Gas Volumes			
1/1/76	36.2¢	37.4¢	38.6¢
1/1/77	43.5	46.6	49.6
1/1/78	51.3	56.2	61.2
1/1/79	59.6	66.6	73.6
1/1/80	69.1	78.6	88.2
B. "Medium" New-Gas Volumes			
1/1/76	37.4	38.9	40.4
1/1/77	45.8	49.4	53.1
1/1/78	54.5	60.3	66.1
1/1/79	63.4	71.5	79.6
1/1/80	73.2	84.0	94.7
C. "Higher" New-Gas Volumes			
1/1/76	38.5	40.4	42.2
1/1/77	47.9	52.1	56.3
1/1/78	57.4	63.9	70.5
1/1/79	66.8	75.9	84.9
1/1/80	76.9	88.6	100.3

Field Price 1/1/75 = 31.2 cents per Mcf

Source: Derived using the projected volumes for regulated sales (Table 7, column (a)) and for all deregulated gas including new sales (Table 7, column (d)), together with the prices for regulated sales (Table 5, column (b)) and the alternative assumed market prices for unregulated sales ($1.25, $1.50, and $1.75).

Table 9

PROJECTED INCREASE FROM JANUARY 1, 1975 IN COST PER MCF TO RESIDENTIAL CONSUMER, PARTIAL DEREGULATION

	Market Price for Unregulated Sales:		
	$1.25	$1.50	$1.75
	(Cents per Mcf at 14.65 Psia)		
A. "Lower" New-Gas Volumes			
1/1/76	5.0¢	6.2¢	7.4¢
1/1/77	12.3	15.4	18.4
1/1/78	20.1	25.0	30.0
1/1/79	28.4	35.4	42.4
1/1/80	37.9	47.4	57.0
B. "Medium" New-Gas Volumes			
1/1/76	6.2	7.7	9.2
1/1/77	14.6	18.2	21.9
1/1/78	23.3	29.1	34.9
1/1/79	32.2	40.3	48.4
1/1/80	42.0	52.8	63.5
C. "Higher" New-Gas Volumes			
1/1/76	7.3	9.2	11.0
1/1/77	16.7	20.9	25.1
1/1/78	26.2	32.7	39.3
1/1/79	35.6	44.7	53.7
1/1/80	45.7	57.4	69.1

Source: The difference between the projected field price in each future year for all sales, under old and new contracts (Table 8) and the average field price as of 1/1/75 (31.2 cents per Mcf).

Table 10

PROJECTED ANNUAL COST TO RESIDENTIAL CONSUMER, PARTIAL DEREGULATION

	Market Price for Unregulated Sales:		
	$1.25	$1.50	$1.75
A. "Lower" New-Gas Volumes			
1/1/76	$186.00	$187.44	$188.88
1/1/77	199.76	198.48	202.08
1/1/78	204.12	210.00	216.00
1/1/79	214.08	222.48	230.88
1/1/80	225.48	236.88	248.40
B. "Medium" New-Gas Volumes			
1/1/76	187.44	189.24	191.04
1/1/77	197.52	201.84	206.28
1/1/78	207.96	214.92	221.88
1/1/79	218.64	228.36	238.08
1/1/80	230.40	243.36	256.20
C. "Higher" New-Gas Volumes			
1/1/76	188.76	191.04	193.20
1/1/77	200.04	205.08	210.12
1/1/78	211.44	219.24	227.16
1/1/79	222.72	233.64	244.44
1/1/80	234.84	248.88	262.92

Source: Increase per Mcf, from Table 9, times estimated annual consumption per customer of 120 Mcf added to the existing annual average cost to residential consumer of $180.00.

Table 11

PROJECTED INCREASE IN ANNUAL COST TO RESIDENTIAL CONSUMER, PARTIAL DEREGULATION TOTAL INCREASE FROM EXISTING LEVELS

	Market Price for Unregulated Sales:		
	$1.25	$1.50	$1.75
A. "Lower" New-Gas Volumes			
1/1/76	$ 6.00	$ 7.44	$ 8.88
1/1/77	14.76	18.48	22.08
1/1/78	24.12	30.00	36.00
1/1/79	34.08	42.48	50.88
1/1/80	45.48	56.88	68.40
B. "Medium" New-Gas Volumes			
1/1/76	7.44	9.24	11.04
1/1/77	17.52	21.84	26.28
1/1/78	27.96	34.92	41.88
1/1/79	38.64	48.36	58.08
1/1/80	50.40	63.36	76.20
C. "Higher" New-Gas Volumes			
1/1/76	8.76	11.04	13.20
1/1/77	20.04	25.08	30.12
1/1/78	31.44	39.24	47.16
1/1/79	42.72	53.64	64.44
1/1/80	54.84	68.88	82.92

Existing Annual Cost = $180.00

Source: Increase per Mcf, from Table 9, times estimated annual consumption per customer of 120 Mcf.

Table 12

PROJECTED YEAR-TO-YEAR INCREASE IN ANNUAL COST TO THE RESIDENTIAL CONSUMER, PARTIAL DEREGULATION

	Market Price for Unregulated Sales:		
	$1.25	$1.50	$1.75
A. "Lower" New-Gas Volumes			
1/1/76	$ 6.00	$ 7.44	$ 8.88
1/1/77	8.76	11.04	13.20
1/1/78	9.36	11.52	13.92
1/1/79	9.96	12.48	14.88
1/1/80	11.40	14.40	17.52
B. "Medium" New-Gas Volumes			
1/1/76	7.44	9.24	11.04
1/1/77	10.08	12.60	15.24
1/1/78	10.44	13.08	15.60
1/1/79	10.68	13.44	16.20
1/1/80	11.76	15.00	21.12
C. "Higher" New-Gas Volumes			
1/1/76	8.76	11.04	13.20
1/1/77	11.28	14.04	16.92
1/1/78	11.40	14.16	17.04
1/1/79	11.28	14.40	17.28
1/1/80	12.12	15.24	18.48

Existing Annual Cost = $180.00

Source: Table 11.

Appendix A

Technical Note

Appendix A

TECHNICAL NOTE

This Appendix describes the procedures used in the contract-by-contract analysis which was employed to develop information on projected field prices under continued FPC regulation in accordance with existing rate ceilings and to determine the gas volumes for contracts which are scheduled to expire by their own terms after January 1, 1975.

The study of natural gas prices for interstate sales is based on a sample which includes all contracts for the sale of gas to interstate pipelines with 1971 or 1972 delivery volumes of 2,000,000 Mcf or more (as reported to the FPC on Form 301-B) and all contracts initiated after 1972 which had estimated annual volumes of 2,000,000 Mcf or more. For the contracts under which deliveries were made in 1972, the volumes used, in all instances, were the actual delivery volumes for the year 1972. For the contracts which cover sales initiated after January 1, 1973 (on file with the FPC through December 31, 1974), the estimated annual volumes reported to the FPC by the producers (in filings to the national rate established by Opinion No. 699-H) were used.

The actual 1972 volume for the contracts included in the sample represents 69.4 percent of the total volume purchased in that year by interstate pipeline companies from domestic gas producers. The estimated volumes for the sales initiated after January 1, 1973, included in the study represent approximately 75 percent of the total of such sales on file with the FPC through December 31, 1974. A total of 1,605 sales were included.

The following information was recorded for each sale in each subarea: the contract rate applicable at January 1 of each year 1975 through 1980; the maximum rate applicable for the sale at January 1 of each year 1975 through 1980 under FPC area rate ceilings; the 1972 volume (or, where no deliveries were made in 1972, the estimated annual volume); the date of contract; the date of initial delivery; the date of expiration of the contract; and price adjustment provisions in the contract, including favored-nation provisions, redetermination provisions, and area rate clauses. Where the relevant information was not uniform for all gas sold under a given FPC rate schedule, the several parts of the sale were treated separately.

All prices were adjusted, where appropriate, for applicable tax or tax reimbursement, for Btu content, and for quality differences. Contract adjustment provisions were applied to contract prices, and the adjustment provisions of the various FPC orders setting forth applicable area rates were applied to the applicable area rates. All price and price-related information is shown in accordance with filings made with the FPC through December 31, 1974.

The volume figures were projected through 1980, using the assumptions that (a) deliveries would be maintained at the 1972 level during the first five full years of deliveries for each sale; (b) deliveries would decrease by five percent annually during the sixth to tenth full years; and (c) deliveries would decrease by 10 percent annually in the eleventh and subsequent years.

Sales which qualify for the new national area rate established by the FPC in Opinion No. 699-H, issued December 4, 1974, were identified separately. These include: (1) sales from wells commenced on or after January 1, 1973; (2) sales made pursuant to new contracts dated on or after January 1, 1973 (where the gas has not previously been sold in interstate commerce, except pursuant to an emergency commitment or pursuant to a limited-term certificate with pre-granted abandonment authorization); and (3) sales made pursuant to contracts executed prior to or subsequent to the expiration of the term of the prior contract where the sales were formerly made pursuant to permanent certificates of unlimited duration where such prior contracts have expired of their own terms on or after January 1, 1973; or pursuant to contracts executed on or after January 1, 1973, where the prior contract expired by its own terms prior to January 1, 1973.

A computer program was developed to perform two major operations: Step 1 determined the "applicable ceiling rate" for each sale at each January 1, 1975 to 1980, both in accordance with Docket No. R-478 covering "old" gas and in accordance with Opinion No. 699-H issued December 4, 1974 and prescribing rates for "new" gas.1/

Step 2 selected, for each sale, the actual "applicable rate" under Docket No. R-478 (old gas) or Opinion No. 699-H (new gas),

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1/ Both the "old" and "new" gas ceiling rates were recorded for each sale inasmuch as "old" sales may qualify for the "new" gas rates at future dates following the expiration of the existing contracts.

whichever was applicable at the given date, using the information on contract prices, price-adjustment provisions, applicable maximum rates under existing FPC area rate ceilings, and related data, together with the "applicable ceiling rates" developed in Step 1.

In Step 1, deriving "applicable ceiling rates," the starting point for "new" gas ceilings was the Opinion No. 699-H nationwide base rates as of each January 1. For "old" gas ceilings, inasmuch as the Commission has not yet issued its Opinion in Docket No. R-478, the starting point was the nationwide rate ceiling recommendation made by FPC Staff in that proceeding. (See Notice Issuing Staff Rate Recommendation and Prescribing Procedures, issued September 12, 1974, Appendix C, R-478.) Data on tax-inclusive ceiling prices were prepared for each state. These tax-inclusive prices were derived using both the tax percentages and cents-per-Mcf taxes applicable for each state. County, local, or other taxes not uniformly collected throughout a state were not included. For Louisiana, account was taken of sales outside state taxing jurisdiction and, for sales within state taxing jurisdiction, of those contracts subject to taxes of 3 cents per Mcf or 4 cents per Mcf, as well as the full 7-cent per Mcf rate. Using the tax-adjusted ceiling prices for each state, the ceiling prices for each individual sale were determined via the computer program, giving effect to Btu adjustment, deductions for wellhead delivery for Docket No. R-478 rates, and applicable quality deductions. For Opinion No. 699-H rates, the applicable gathering allowances were accounted for separately for each subarea, as prescribed in that order.

In Step 2, designed to determine the actual rate which would be applicable for each sale at each January 1 under FPC regulation, each sale was classified at each future date in one of the following classifications listed below. Where two or more of the categories were applicable, the first-listed was used. The listing below shows the applicable rates attributed to each sale:

A. Expired contracts (after the expiration date)

   The applicable Opinion No. 699-H ceiling.

B. Sales Under Optional Procedure (FPC Order No. 455)

   The approved rate allowed under each optional procedure sale.

C. Sales Qualifying for Rate Treatment Under Opinion No. 699-H

   1. Sales with area rate clauses or with favored-nation provisions

      The applicable Opinion No. 699-H ceiling rate (from Step 1).

   2. Sales with redetermination provisions

      For all dates subsequent to the date of redetermination, the applicable Opinion No. 699-H ceiling rate (from Step 1).

   3. All other sales

      The contract rate at each date was compared with the applicable Opinion No. 699-H ceiling and the lower figure was selected.

D. Sales Under Docket No. R-478

1. Sales with area rate clauses

   The higher of the Docket No. R-478 applicable ceiling rate (from Step 1) or the maximum applicable area rate under existing FPC area rate ceilings.

2. Sales with redetermination provisions

   For all dates subsequent to the date of redetermination, the higher of the Docket No. R-478 applicable ceiling rate (from Step 1) or the maximum applicable area rate under existing FPC area rate ceilings.

3. Sales qualifying for minimum rate

   The minimum rate.

4. All other sales

   (a) The Docket No. R-478 applicable ceiling rate (from Step 1) was compared with the maximum area rate applicable under existing FPC area rate ceilings and the higher figure was selected.

   (b) The contract rate at each date was compared with the figure selected in operation (a), above, and the lower figure was selected. This second comparison yielded the actual rate applicable for the given sale.

Where a sale has been authorized by the FPC, by an order issuing special relief, at a price higher than that derived by the procedures outlined above, the price permitted by the special-relief order was used in the revenue computations.

In preparing estimates of total volumes and revenues for all sales to interstate pipeline companies on the basis of the sample, the data were classified into the following nine major areas:

1. South Louisiana Offshore
2. South Louisiana Onshore
3. Permian Basin
4. Texas Gulf Coast
5. Hugoton-Anadarko Area
6. Other Southwest
7. Appalachian-Illinois
8. Rocky Mountain
9. Other (California, Arizona, and Florida)

For each area, the sample volumes and revenues for all time periods were expanded to totals.

This expansion was performed separately for sales with 1972 delivery volumes and for sales initiated on or after January 1, 1973 and the resulting estimates of total revenues and volumes were then combined. The sample volumes (and revenues) for sales with 1972 volumes were adjusted to totals using the ratio between (1) the 1972 total volume for all sales (excluding emergency sales and limited-term sales) as reported in the FPC publication, Sales by Producers of Natural Gas to Interstate Pipeline Companies, 1972, and (2) the 1972 volume for the initial sample examined. The sample volumes (and revenues) for sales after January 1, 1974 were adjusted to totals using the ratio between (1) the total estimated annual volume under all such sales filed through December 31, 1974 and (2) the estimated volume for sales in the sample.

The procedure described above provided information on projected revenue per Mcf for future deliveries under contracts initiated through the end of 1974, under continued FPC regulation, using the existing FPC ceiling prices. This information is shown in Table 5.

Additionally, the contract study was used to obtain the 1972 (or estimated) volume for contracts expiring in each of the years 1975-1980 (Table 1). The study also was used to obtain data on projected future volume and regulated price for all contracts expiring after January 1, 1975 and prior to each future date (Tables 2, 3). The procedures used to expand the sample data on expiring contracts to estimated totals are the same as were described above for the entire sample.

TESTIMONY OF JAMES F. FLUG

Director & Counsel

EAC

January 29, 1976

During the past few months, Congress has been inundated with claims that there was a "natural gas crisis" this winter. The only "solution" offered by the industry was unlimited increases in the price of gas through elimination of the "reasonable return" standard for gas pricing.

Calm analysis since the original flurry of industry claims has shown that:

-- The panic atmosphere was unwarranted, since the total amount of gas available this winter -- and next -- is adequate to meet the nation's needs as long as the industry distributes it properly.

-- To the extent that there might have been a temporary supply tightness in certain areas, the responsibility rests with those in the industry itself who have diverted huge amounts of offshore gas away from the interstate market; with other producers who have failed to meet production committments; with still others who have apparently stolen interstate gas to sell in intrastate markets; with pipelines who have both failed to resist ~~with~~ suppliers' defaults and have refused to purchase temporary supplies to meet their own committments; and with the FPC which has permitted substantial diversions of interstate gas and has failed to enforce supply committments;

-- The total U.S. natural gas reserves are substantially larger than industry and goverment statistics have previously indicated.

-- Deregulation of natural gas prices provides no short term relief nor will it reverse the long term , unavoidable decline in gas reserves, but it will raise prices substantially, so that the consumer will get no significant return for a very heavy price.

Those are the facts, and the full story is contained in the enclosed "Natural Gas Fact Book" which I urge you to read and consider.

We have come to a very unpleasant conclusion, after studying the investigative hearings of the Moss and Dingell subcommittees and the reports of GAO, Library of Congress, and Office of Technology Assessment, and contrasting them with the advertising and lobbying materials of the industry. Our conclusion is not only that the case for deregulation fails on the merits, but also that there has been an attempt by the industry to stampede the Congress into a panic decision that would ignore the merits. The oil and gas lobby apparently recognized that if Congress moved carefully and thoughtfully it would never let the industry have the multi-billion dollar windfall which deregulation would produce, and would never impose the costs of that windfall on the American consumer. Thus, it has tried to "bootstrap" permanent deregulation onto temporary legislation originally designed to meet an alleged "emergency" which the industry itself created and promoted.

Its latest effort in this direction has been to utilize a nearly unprecedented rule to short-circuit the orderly process of the Interstate and Foreign Commerce Committee, which is moving expeditiously towards reporting out a carefully crafted long-term gas policy legislation.

You will be hearing more about the rule that the industry is supporting in its last ditch attempt to get the House to act precipitiously. But obviously, the Floor of the House is no place for the first mark-up of a complex and vital piece of energy legislation, with tens or hundreds of billions of industry profits and consumer costs handing in the balance.

The last time the industry tried to deregulate natural gas, in the 1950's, President Eisenhower found the industry's lobbying tactics so obnoxious that he vetoed the legislation those tactics had produced. Especially, so soon after Watergate, and with the revelations of illicit oil industry activites, we can ill-afford to mark our bicentennial with another massive scandal. Yet, the evidence already available strongly suggests that when the full truth about the current gas deregulation campaign is known, it will reveal another scandal. The House can free itself from the industry machinations by moving carefully and on the merits. This requires defeat of the industry-supported special Rule, rapid completion of the Committee hearings, detailed Committee discussion and mark-up, and full House consideration under the normal rules.

Statement
of
Leonard Woodcock, President
United Automobile, Aerospace and Agricultural Implement
Workers of America (UAW)
before the
Subcommittee on Energy and Power
of the
House Committee on Interstate and Foreign Commerce
on
Regulation of Natural Gas

January 29, 1976

My name is Leonard Woodcock. I am President of the International Union, United Automobile, Aerospace and Agricultural Implement Workers of America, UAW. We represent 1,415,000 UAW members.

I appreciate this opportunity to testify on issues related to long-term pricing policy for natural gas. Those comments do not deal with any particular piece of legislation now before the Congress; instead they identify some key aspects of the natural gas industry, and describe some principles that should be incorporated in any action by Congress.

Before getting into that, some comments are needed with respect to the short run.

Congress is currently considering legislation which was developed to meet the possibility of large employment disruptions this winter or next if factories -- and other business establishments -- were unable to obtain sufficiant supplies of natural gas. Since sources of data regarding natural gas supplies, and possible shortages, are quite unreliable, we in the UAW were skeptical that employment disruption actually would occur. Nevertheless, because we were not able to rule out the possibility of such events, we have not opposed the legislation provided it is restricted to dealing only with the short run. Unfortunately, others have attempted to use this as an opportunity to ram through changes in long-term pricing policy. That effort should be strongly resisted; if necessary, the "emergency" legislation should be defeated rather than allow it to be used as a hostage by those who want to achieve deregulation.

There is, in fact, less basis now for concern over the short-term situation than there was previously. Last summer both the natural gas industry and the Administration attempted to frighten the people and the Congress into believing that the current disastrous recession might lapse into a full-scale depression this winter as businesses and factories all over the country shut down for lack of natural gas. We were told that as many as 100,000 jobs would be lost. More recently, however, the General Accounting Office has concluded that these predictions were "misleading." It surveyed eight of the major states for which economic disaster had been forecast and found that there were no "broad areas of projected large-scale unemployment" or plant shutdowns due to natural gas shortages.

Mild weather conditions in the early winter and the recession levels of industrial activity undoubtedly helped to curtail demand, and there is still a possibility of short-term problems. But there is no justification for our being stampeded into ill-considered long-term alterations of the regulatory procedure to meet a crisis that simply hasn't occurred and appears less likely each day.

The remainder of my testimony will deal with the long-term question.

It must be emphasized that there will be a continuing need for regulation of natural gas prices. Such regulation is needed for two purposes: to prevent monopolistic profiteering and to prevent windfall profits.

The monopolistic structure of the industry concerns us greatly. In many cases only one or two long-distance pipelines are available to distribute gas from a particular production area. In the major gas-producing regions of the country, the eight largest producers control between 62 percent and 100 percent of the gas reserves not yet committed to sale. Rather than actively compete with one another, these companies often collaborate together on joint economic ventures. This presents the continued danger of monopolistic profiteering -- the decision by a single company or a group of companies to restrict output and drive up the market price. As Senator Philip Hart of Michigan recently put it, we cannot "lift price regulation in the natural gas industry until we take steps to make this a competitive market."

Unfortunately, even a competitive natural gas market would not solve all of our problems. For better or for worse, our nation has never followed the tradition of some other countries that permit private ownership of surface lands but reserve to the state full ownership of sub-soil mineral rights. As a result, a large portion of the actual and potential natural gas reserves of the country are privately owned, and every increase in natural gas prices means windfall profits for the owners of uncommitted gas reserves. Even a competitive price -- when it rises sharply as a response to increases in the prices of alternative fuels -- holds out the potential for undeserved windfall gains.

The Supreme Court summed up the argument when it ruled in the Phillips case in 1954 that the aim of the 1938 Natural Gas Act was "protection of consumers against exploitation at the hands of the natural gas companies." The Library of Congress summed up the stakes when it recently estimated that the annual cost of deregulation would be $5 billion in the first year and $18 billion within seven years.

The current artificial distinction between interstate and intrastate marketing should be ended. Federal regulation should apply to all natural gas, whether or not it is transported across state lines.

Serious economic distortions are occurring as a result of the present segmentation of the market for natural gas. Producers have great incentive to divert supplies to the intrastate market. The FPC helped aggravate the shortage on the interstate market by making it easier for the companies to do just this. Most potential users within producing states can obtain new supplies at a high price, while potential new users in other states cannot obtain supplies at any price. Factories in some of the non-producing states may eventually be forced to close or to relocate in producing states, creating unnecessary unemployment and personal hardship.

On a long-term basis, the existence of an unregulated market holds out a constant temptation for producing companies to act together to restrict the supply on the regulated market, thereby creating a shortage that they will meet at a higher price on the unregulated market. The sensible long-term answer is to create a single, regulated national market.

Natural gas regulation must include procedures that supplement the control of well-head prices. By doing that, steps can be taken to provide incentives for needed expansion in production, and minimize hardship.

The present system is not sufficiently adaptable to efficiently control supply and demand, and that leads the producers to hope that the regulatory systems will prove to be inadequate. To some extent -- but not entirely -- that accounts for shortages which have occurred. Ever since the election of Richard Nixon in 1968, the federal administration has been holding out to natural gas producers the prospect of deregulation of production. Nixon appointees to the Federal Power Commission have systematically engaged in the partial deregulation of the industry. One producer privately estimated that total deregulation would permit it a price increase of 450 percent. Faced with this tempting prospect, many producers have undoubtedly been speculatively hoarding their reserves, keeping them off the market in anticipation of large windfall gains from eventual deregulation.

Certainly there are pressures that will cause natural gas prices to rise in the future. The prices of alternative fuels -- notably oil and coal -- have skyrocketed, thus stimulating the demand for natural gas as a substitute.

A recent calculation found that heating oil costs 78 percent more per BTU (British Thermal Unit) than natural gas. Costs of exploration go up. In short, energy costs will increase and it is unrealistic to assume that natural gas will be unaffected.

However, that does not imply a need for deregulation. Instead it indicates the need for controlled increases in prices paid to producers -- in order to stimulate production -- with price differentials based on costs of production, taxes, or other devices, to avoid windfall profits. On the consumer side, it indicates the need for a multiple pricing system that will protect residential users (and others) from hardship, while discouraging inefficient use, such as for boiler fuel, etc. Techniques such as these will facilitate adaptation to changing circumstances, and thus counteract the efforts of those who hope the regulatory mechanism will fail.

The government must have more reliable information regarding natural gas supplies. The Federal Power Commission uses reserve data provided by the industry in setting rates. Recent U.S. Geological Survey estimates for reserves in federal offshore fields in Louisiana were 50 percent higher than industry figures. The staff of the Federal Trade Commission, however, found a major case in which reserves were underrated by 50 percent, and it has charged that the industry reporting procedures "are tantamount to collusive price rigging." If we are to have democratic control of our energy resources, government must have the full power to obtain and to verify basic energy information.

Of course, natural gas is only one source of energy and it should be dealt with in the context of our overall energy needs and supplies. The UAW firmly believes that the nation needs a comprehensive program to deal with energy matters, and we have on many occasions set forth our suggestions to achieve that. The key mechanism required is a National Energy Production Board which would be charged with planning and executing a vigorous program to develop our energy resources. I will not go into details now regarding the Board,* but I do want to emphasize the need for establishing it and providing authority to make loans, contract with the private sector, enter into joint ventures, and undertake its own activities where necessary, in order to break bottlenecks and stalemates and to develop new initiatives. That would permit us to have a truly comprehensive national energy program, which would determine specific targets regarding all forms of energy and develop the procedures necessary to achieve those goals.

Within the framework of such an energy program, improved regulation of natural gas would play a vital role. In order to effect that, uncertainty about our long-term pricing policy must be reduced. By holding out the prospect of deregulation, the Administration gives the gas industry a powerful incentive to withhold reserves from production and to create shortages. We must finally make clear to the industey that it will continue to be regulated, that it can expect somewhat higher prices when they are really needed, but it cannot expect to drive prices sky high at will. Then we will see an end to the actual and potential shortages that have been plaguing both businesses and consumers.

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* I have presented more detailed comments to the Congress, for example, in testifying on S 740.

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DEREGULATION OF NATURAL GAS

PREPARED STATEMENT OF

EUGENE H. LUNTEY

President &
Chief Executive Officer
The Brooklyn Union Gas Company
Brooklyn, New York

before the

COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
SUBCOMMITTEE ON ENERGY AND POWER
UNITED STATES HOUSE OF REPRESENTATIVES

January 30, 1976

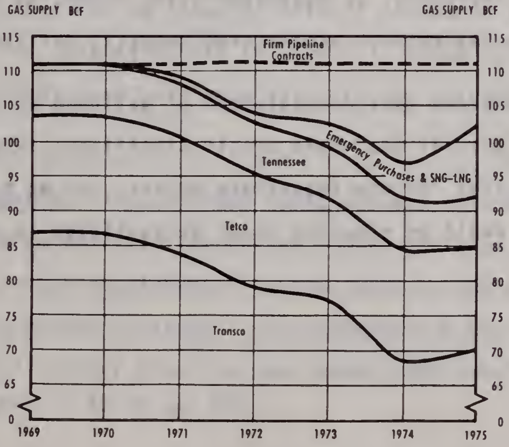
Gentlemen:

My name is E. H. Luntey, and I am President and Chief Executive Officer of the Brooklyn Union Gas Company. I am speaking to you today on behalf of more than four million people who reside in three of New York City's five boroughs and who rely exclusively on the Brooklyn Union Gas Company for natural gas, which provides more than 40% of all their domestic energy requirements. In addition, I speak in the interest of more than 40,000 business establishments which employ at least 250,000 people and depend on natural gas for their source of energy. Last of all, but not least, I appear for more than 30,000 investors and a pollution-plagued city whose best interests all revolve around the need for a continued and adequate supply of a clean burning, efficient, and economic source of fuel.

Since 1971, the supplies of natural gas available to our customers have been declining due to the curtailment of deliveries by the pipeline companies with whom we do business. Brooklyn Union has purchased its natural gas supplies from three pipeline companies, Transcontinental Gas Pipe Line, Texas Eastern Transmission Corporation, and Tennessee Gas Pipeline Company. The vast majority of the gas production supplied to these pipeline companies comes from non-affiliated producers in the Texas and Louisiana areas. Since 1971, production from the fields in these areas has either diminished through natural depletion or has been unavailable to the interstate pipelines, due to an unnatural or regulated wellhead price which is equal to only a fraction of the competitive market value and which is below the cost of finding new gas.

The declines in volumes of gas available to Brooklyn Union are indicated on the chart provided; and these declines are most pronounced in the case of Trancontinental, which represents 78% of our contracted pipeline volumes. The volume of gas which Brooklyn Union was able to purchase from the pipelines in 1975 was 17% less than the amount contracted for and actually purchased in 1969. Brooklyn Union's firm customers, who have no alternative fuel immediately available to them, will require an estimated annual volume of 95,000 MMCF for the year 1976. Of that amount, 83% is required to meet the needs of homeowners for heating, water heating, and cooking. We will be able to meet these high priority needs only because we have been able to import some liquified natural gas and to produce synthetic gas from naphtha, which, ironically, costs significantly more than the highest prices for intrastate sales of natural gas.

BROOKLYN UNION GAS COMPANY
SOURCES OF GAS SUPPLY
1969-1975



Current projections of gas supply from our pipeline companies indicate a worsening of our situation after 1976. We estimate that curtailments to Brooklyn Union could reach a disastrous level of about 40% or twice the current level by 1983. However, curtailments could be worse if the advance payment programs of our pipeline suppliers are less than successful. It is quite likely that the degree of success achieved by these programs, in terms of economic reserves discovered, will vary directly with the wellhead price.

In an effort to procure adequate supplies to offset these future curtailments, Brooklyn Union has undertaken a number of diversified gas supply projects in addition to the construction of our SNG plant. These efforts include a small scale exploration and development project in the Appalachian area, the importation of LNG from Algeria, and various other attempts to produce or procure synthetic fuels. However, even if all of these potential supplemental sources of gas were obtained in full, the company would not have protection for an extremely cold winter. It is also very likely that some of these supplemental volumes will not be obtained; and, therefore, we must make every effort to obtain additional gas reserves through accelerated domestic drilling programs.

We are convinced that deregulation of wellhead prices for new dedications of natural gas would elicit significant volumes of additional supplies for the interstate market, and we believe that the cost which could be expected under deregulation is economically justified.

In order to demonstrate the economic logic in favor of deregulation, I have had a simplified tabulation prepared showing the average cost of gas to Brooklyn Union's customers as actually experienced in 1975 and as adjusted for three hypothetical situations: (1) curtailed service, (2) deregulation, (3) synthetic and imported fuels.

Case (1) - Curtailed Service assumes that there would be no deregulation or increase in the wellhead price of gas and that B.U.G.'s pipeline curtailments would increase to the 40% level, necessitating the curtailment of sales to B.U.G.'s firm customers. This decline in sales would result in a 26% increase in Brooklyn Union's average prices as a result of spreading the fixed costs of both Brooklyn Union and its pipeline suppliers over a smaller volume of sales.

Case (2) - Deregulation assumes that deregulation of prices for newly dedicated gas volumes occurs and that the additional volumes of gas necessary to maintain Brooklyn Union's normal level of firm sales are acquired by the pipelines at a price of $2.00. The resultant price increase to Brooklyn Union's customers is only 20%, or less than the increased cost in Case (1), which assumed no additional volumes were available for sale and that we curtailed firm customers.

Case (3) - Synthetic and Imported Fuels assumes that the additional volumes needed to maintain the current level of sales will be obtained from other supplemental sources such as SNG or imported LNG at a price of $3.50 per MCF. The resulting price increase of 26% is again higher than the case where additional pipeline gas is available at $2.00 per MCF.

AVERAGE RATE ($/MCF)

	Actual 1975	Curtailed Service (1)	Deregulation (2)	Synthetic and Imported Fuels (3)
Capital Expenses	$ .57	$ .72	$ .57	$ .57
Operating & Maintenance	1.32	1.67	1.32	1.32
Gas Costs	1.16	1.45	1.78	1.94
Total	$3.05	$3.84	$3.67	$3.83

The mechanics of this calculation are documented in an appendix to this statement. Despite the obvious oversimplification of such a projection, the principles illustrated and the conclusions drawn are valid:

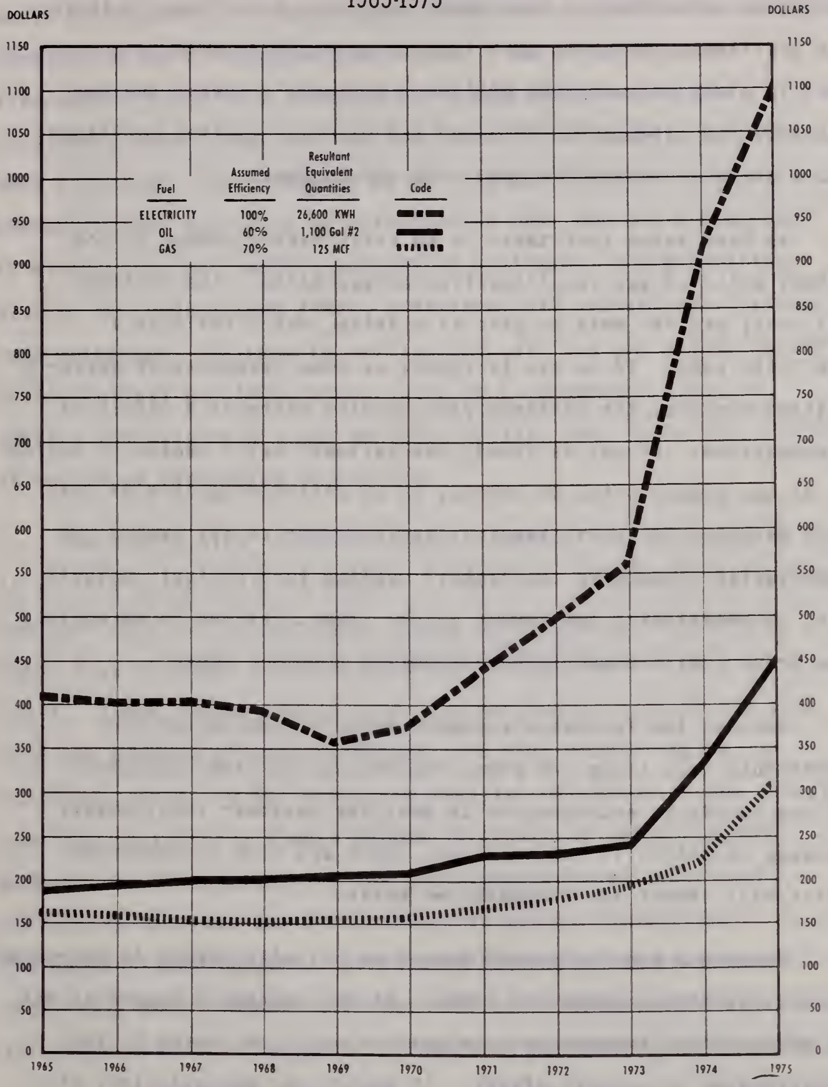
1. A 300% increase in the wellhead price of new gas ($.52 to $2.00/MCF) will result in only a 20% increase in the customer's average rate.

2. Either the use of supplemental gas supplies or the absence of additional supplies will result in higher prices than those resulting from a $2.00 price for new pipeline gas.

There are, of course, other economic factors which are relevant to the issue of deregulation and will impact on the cost of energy to a consumer. Natural gas is presently the cheapest form of fuel that can be used for heating, water heating, and cooking in smaller-size dwellings in our territory. Thus, if sufficient quantities of gas are unavailable, conversion to an alternate fuel will result in expensive appliance conversion costs, as well as operating costs higher than that for gas. In the case of electricity, almost four times as much.

COMPARATIVE ANNUAL COST OF HEATING TYPICAL HOUSE IN BROOKLYN UNION'S SERVICE AREA

1965-1975



The capital cost for a customer to convert to another fuel is substantial and must be given proper consideration. Brooklyn Union's customers alone have an investment of almost $1 billion in their gas appliances, which is more than twice Brooklyn Union's investment in plant of over $500 million. At today's costs, the purchase of new oil-burning furnaces and electric cooking appliances would place an impossible burden on the customer.

We have shown that there is no earthshaking change in the retail price of gas resulting from deregulation. The customer will only pay for what he gets at a price, which reflects a realistic cost. If no gas is found, as some opponents of deregulation contend, the consumer pays nothing extra as a result of deregulation. If gas is found, the customer has a choice of buying it at the higher price or turning to an alternative form of fuel such as oil. At least, however, the customer is not denied the opportunity to acquire the highest quality form of fuel, natural gas, at potentially the lowest price. Thus, failure to deregulate the price limits competition and defies economic logic.

Besides the favorable economic impact of decontrol over substitute gas, there are other reasons why we favor decontrol. If gas supply is not adequate to meet our customer requirements because decontrol is not approved, there are dire consequences which will impact the community we serve.

Placing a huge increased demand on oil will result in increased imports at higher costs and risks. If the increased demand is met by electricity, tremendous acceleration would be needed in the construction of nuclear plants. It would take approximately six

1,000 Mw nuclear plants at a cost today of approximately $4.5 billion (excluding transmission and distribution cost, which would be sizeable) to supply the useful energy supplied by gas in Brooklyn Union's franchise area alone. The efficiency of alternative fuels is a question which must be considered in evaluating this energy problem and gas is well recognized as the most efficient form of energy as well as the cleanest. The net energy concept must also be evaluated so that the BTU's required to manufacture and install conversion equipment, new generating plants, new underground lines, additional oil trucks, etc. are not underestimated. Failure to utilize the existing gas energy system to its fullest possible extent would be a tremendous waste of capital and resources - and we fully believe that to be the result of continued regulation of new gas.

There will also be other economic impacts on the community if we have a shortfall in supply. Industrial and commercial sales comprise only 17% of our total sales, and these establishments might have to close unless they could quickly convert to other fuels. These establishments are only marginally tied to New York City now because of other problems, and they should not be, in addition, subjected to inadequate supplies of energy at the lowest possible cost. If all were forced to close, at least 250,000 workers would be unemployed and the community would lose $2.2 billion in salaries and $4.3 billion in sales, value added and capital improvements. Certainly, some of these businesses, especially those dependent on the form value of gas, would be forced to move to other parts of the country where gas is available from the intrastate market. While we cannot predict the extent to which these economic losses will become reality, any impact will certainly be devastating to a city already on the precipice of financial disaster.

These factors all underscore the need for additional production of natural gas which we are confident will result from the deregulation of wellhead prices. It appears, however, that the legislation proposed to resolve this issue has somehow become senselessly entangled with another unrelated issue - the regulation of retail prices by the enactment of incremental pricing provisions with respect to deregulated sales. Incremental pricing has worked at the pipeline level in the past; however, it simply will not work at the distribution level.

The effects of arbitrarily assigning higher costs to a particular type of customer invites the re-enactment of all the economic mistakes and misallocations which we have endured as a result of maintaining arbitrary and uneconomic price levels at the wellhead. Such a provision would create the potential for disincentives on the part of pipelines or distribution companies to serve particular geographic areas and companies or particular types of customers at any price.

In addition, any form of incremental pricing which must relate a unit of gas produced at the well with a sale to a retail customer 2,000 miles and three transactions removed from its origin, is difficult to conceptualize and impossible to implement on any practical basis.

In summary, decontrol is a prudent action since it will cost nothing if no new gas is discovered. If additional volumes are found which contribute to long-term security of supply, the increased costs to our customers will be lower than any other alternatives. It is the only way to test the availability of gas supply along existing pipelines. If decontrol of new gas seems to be generating impossible economic burdens on consumers or unjustified profits for producers at some future time, Congress can always reregulate. Failure to act in the light of changing conditions is failure to respond to the duty entrusted by the people.

If decontrol is not approved, it will generate economic hardship to gas customers and the entire community served by Brooklyn Union.

As a purchaser of gas, we have a long and excellent track record of representing the consumer. We have no desire to pay more for gas which will make our rates less competitive, but the course of continued regulation has already and will continue to force distribution companies to pay even higher prices for other forms of supplemental gas or deny customers a valuable and much needed energy source.

Opposing deregulation might appear to speak out for lower costs but in fact, as we have demonstrated, is right now costing the consumer more and will continue to do so in the long run. Continued regulation will be the most expensive alternative - expensive in cost and expensive in the loss of a valuable energy resource. Deregulation of the wellhead price of new gas is, we believe, the only way to assure maximum discovery and timely use of our natural gas reserves.

APPENDIX

1975 Data Are For Fiscal 1975 and
Obtained from Brooklyn Union Gas
1975 Annual Report and Review of
Operations

I. Gas Supply (Cases 1, 2, & 3)

1. Firm Pipeline Contract Quantity = Total gas volumes contracted for by Brooklyn Union with its three pipeline suppliers.

2. Curtailment = Firm Pipeline Contract Quantity x 40%

3. SNG Production is based on contract volumes of feedstock.

II. Cost of Gas (Cases 1, 2, & 3)

1. Average Wellhead Price (Case 2) is a weighted average of the quantity of regulated pipeline gas at a 64% system-wide curtailment level x $.30/MCF and the incremental quantity of deregulated gas needed to bring the system-wide curtailment to 45% at $2/MCF.

2. Pipeline Charges per MCF vary based on pipeline throughput since pipeline charges are assumed fixed.

3. Supplemental (Case 3) A price of $3.50/MCF is assumed based on current price estimates for these supplies.

4. Weighted Average Cost of Gas = Gas Costs (See III (2)) ÷ Supply Available for Sale

III. Total Costs (Cases 1, 2, & 3)

1. Sales = Supply Available for Sale-Unaccounted For Gas

   a. Unaccounted For Gas = Supply Available for Sale x 7.5%

2. Gas Costs = (Total Pipeline Supply x Pipeline Cost of Gas)+(SNG Production x SNG Production Cost of Gas)+(Other Supplemental Supply x Supplemental Cost of Gas)

IV. Average Rate = Total Costs ÷ Sales

APPENDIX

I. GAS SUPPLY (MMCF)

	1975	(1)	(2)	(3)
Firm Pipeline Contract Quantity	111,100	111,100	111,100	111,100
Less: Curtailment	19,100	44,400	44,400	44,400
Net Pipeline Supply	92,000	66,700	66,700	66,700
SNG Production	9,800	8,200	8,200	8,200
Additions to Storage	(7,000)	-	-	-
Add'l Gas Due to Deregulation	-	-	19,900	-
Other Supplemental Supply	-	-	-	19,900
Supply Available for Sale	94,800	74,900	94,800	94,800

II. COST OF GAS ($/MCF)

	1975	(1)	(2)	(3)
Pipeline				
Average Wellhead Price	$ .30	$ .30	$ .89	$ .30
Pipeline Charges	.63	.93	.70	.93
Total Cost of Pipeline Gas	$ .93	$ 1.23	$ 1.59	$ 1.23
% Change in Unit Cost From 1975	-	32%	71%	32%
SNG Production	$ 2.29	$ 2.29	$ 2.29	$ 2.29
Supplemental	-	-	-	3.50
Weighted Average Cost of Gas	$ 1.07	$ 1.35	$ 1.65	$ 1.80
% Change in Unit Cost From 1975	-	26%	54%	68%

III. TOTAL COSTS ($000)

	1975	(1)	(2)	(3)
Sales (MMCF)	87,700	69,300	87,700	87,700
Capital Expenses	$ 49,600	$ 49,600	$ 49,600	$ 49,600
Operating & Maintenance	116,000	116,000	116,000	116,000
Gas Costs	101,600	100,800	156,500	170,500
Total	$267,200	$266,400	$322,100	$336,100

IV. AVERAGE RATE ($/MCF)

	1975	(1)	(2)	(3)
Capital Expenses	$ .57	$ .72	$ .57	$ .57
Operating & Maintenance	1.32	1.67	1.32	1.32
Gas Costs	1.16	1.45	1.78	1.94
Total	$ 3.05	$ 3.84	$ 3.67	$ 3.83
% Change in Unit Cost From 1975	-	26%	20%	26%

STATEMENT

of

AMERICAN IRON AND STEEL INSTITUTE

before the

Subcommittee on Energy and Power

U. S. House of Representatives Interstate and Foreign Commerce Committee

January 30, 1976

Mr. Chairman and members of the Subcommittee, Good Morning. I am Harry Thomas, General Manager, Power, Fuel and Materials Distribution of the United States Steel Corporation. I also serve as Chairman of the Committee on Energy of the American Iron and Steel Institute, a trade association representing the domestic iron and steel industry and its related activities, an employer of 750,000 men and women - - an industry that in 1974 paid out ten billion dollars in wages and salaries.

I welcome the opportunity to acquaint you with some of the operating problems which my company and the steel industry, in general, have encountered as a result of the natural gas shortage and to comment on what we see as the only reasonable solution to this problem.

The steel industry of the United States recognizes that it is a major energy consumer having used for a number of years 5 to 6 percent of all the energy consumed in the United States or between 15 and 20 percent of the energy consumed by industry. The steel industry is unique among energy users in the United States because it is the only major industrial consumer which derives the majority of its energy from coal. In 1974, coal supplied 67 percent of the industry's energy requirements; natural gas, 20 percent; petroleum products, 9 percent; and purchased electricity, 4 percent.

The steel industry is not a homogeneous industry, but rather it is a grouping of many firms that have different kinds of facilities and processes, some proprietary, that produce a wide variety of steel products. Elaborating on this statement, it must be recognized that the steel industry includes both fully integrated and non-integrated companies. Fully integrated companies have plants with blast furnaces and coke ovens. This is a significant point because most of the coal used by the steel industry is consumed in the coke oven blast furnace complex for the smelting of iron ore to produce molten pig iron. Both the blast furnace and coke oven produce large quantities of useful coal-based by-product fuels which are an important part of the steel industry energy supply. Non-integrated companies start their processing with a quasi semi-finished material, namely steel scrap, which effectively avoids many of the large energy consuming processes. Since the non-integrated companies do not have molten pig iron from blast furnaces or the by-product fuels from blast furnaces and coke ovens, they depend almost entirely on natural gas, oil, and electricity. However, even integrated companies are dependent on natural gas and oil because the majority of these critical fuels are consumed in finishing operations that have no alternative to gaseous or liquid fuels. In fact, many so called integrated companies have individual plants that do not have blast furnace-coke oven complexes and, therefore, they also require significant quantities of natural gas and oil.

The steel industry is rather unique in terms of fuel usage. We are one of the few industries which have consistently maximized the use of waste by-product gases to fuel operations.

These blast furnace and coke oven gases are of low calorific value but can be used not only to fuel conventional uses such as boilers, but can also be used in certain applications where liquid and solid fuels are not feasible. The use of these gases maximizes our energy conservation efforts, and saves either millions of cubic feet of natural gas per year, or an equivalent volume of oil. But, because production of these by-product gases fluctuates, while processes requiring fuels are relatively constant, natural gas is required to stabilize the heat content and the volumes of by-product gases. Without this natural gas, significant volumes of these waste gases would have to be flared to the atmosphere, and their energy value lost.

The steel industry has many processes for which no technology currently exists by which we could replace natural gas with an alternate fuel. For example, in making specialty products, special protective atmospheres to prevent surface oxidation have to be created in which to process the steel. Natural gas is broken down to create these atmospheres.

In the annealing process, we use significant volumes of natural gas in both direct and indirect flame applications. No technology presently exists to substitute alternate fuels in either application. In the direct flame process, steel is heat treated by many small burners employed to impart a uniform heat placement under exacting temperature control. The use of a liquid fuel on such small burners results in uneven heat transfer which would result in serious debasement of product quality. This disregards the ash contamination problem arising out of the combustion of liquid fuels. This ash causes further deterioration in product quality which strikes at our ability to compete because of the quality levels required by our customers.

In the indirect process, we use radiant tube burners for annealing. Use of a fuel other than a gaseous fuel would create an uneven tube wall temperature resulting in nonuniform heat placement. In addition, the impurities in the liquid fuel would corrode the tubes so badly that the operation would be totally destroyed within a short period of time. No present technology exists for use of alternate fuels in radiant tube burners.

Other problems arise. A new plant is designed with the fuels planned for usage in mind. Thus, although any one of several fuels may be acceptable for a particular process, the process may be designed to accommodate only one such fuel. Not only are the burner systems themselves installed accordingly, but burning chambers and exhaust flues are structured around the fuel choice. In the steel industry, a significant expansion of capacity occurred in the early 1950's. Gas was readily available, in plentiful supply, and with good long-term prospects at the time. It was a premium fuel and was offered at a discount rate when compared to the Btu cost of alternate fuels. Therefore, plants were built to use gas, and the capability to use an alternate fuel was not considered in the design. As a result, we today are at a point where more than mere replacement of a burner is involved in converting some operations. Rather, the entire facility would have to be reconstructed.

An example is a reheating furnace used for processing slabs or billets prior to rolling into the finished product. Modern reheating furnaces are designed for the use of flat flame type radiant burners. In those cases, high energy burners are installed in the furnace roof in close proximity to the product to be heated. In order to achieve the necessary heat placement many furnaces employ over 40 burners in a single furnace. To convert this furnace to the old-type side wall and/or end fired system would require a major redesign of the furnace structure.

Conversions which require not merely installation of a new burner apparatus but complete replacement of the facility involve premature replacement of facilities and significant capital investment. Present predictions are that steel will be in short supply consistently throughout the next ten years. In order to meet this problem and to prevent the type of product shortages which have started inflationary spirals in the past years, industry estimates are that $5 billion of investment in new facilities will be required each year. Just where that money can be raised is a major quandry. But if we are forced to add onto that the cost of complete and premature replacement of some existing facilities so that we can maintain even current levels of production, we will be unable to expand our capacity, and the foreign steelmaker will be the beneficiary.

The steel industry is heavily concentrated in three states: Indiana, Pennsylvania, and Ohio. These three states are served by three of the five pipelines identified by the Federal Energy Administration as the most seriously curtailed pipelines in the country--Panhandle Eastern Pipe Line Company, Columbia Gas Transmission Corporation and Texas Eastern Transmission Corporation. Only through emergency purchases of natural gas, the low level of the economy, the normal winter weather, and the completion of many gas-to-oil conversion projects coupled with the plentiful fuel oil supply has spared the steel industry from what could have been a disaster.

United States Steel, along with most of the steel industry, has sought to reduce the impact of these shortages by an active program of conversion and conservation. However, as I have discussed earlier, certain critical uses remain which we just cannot presently convert.

Because of these facts of our existence, and the absolute necessity of natural gas to our continued operation, it is imperative to us that we secure dependable, long-term sources of supply by which we can assure adequate supplies of natural gas for our nonsubstitutable uses.

This can best be accomplished by deregulation of natural gas. As you know, the Senate has passed S. 2310 which provides for deregulation of new onshore gas as of April 5, 1976 and a five year phased-in deregulation of new offshore gas. We support this initial move to deregulation as a recognition of the importance of the marketplace in making it possible to explore for and develop new natural gas supplies.

Existing controls over natural gas prices have led to wasteful use and discourages the investment that must be made to find new reserves. As reserves dwindle, production eventually has to drop.

One has only to look at the recent, well advertised history of gas availability in the Texas intrastate market to see the benefits of proper drilling incentives. Four years ago, the Texas interstate and intrastate gas prices were similar and the drilling activity had declined. Increased demand from normal growth and environmental restrictions without an adequate supply increased the price of gas to the point where drilling was again profitable. Today there is no shortage of gas in the Texas intrastate market. The same effect, but perhaps not such a dramatic one, can be expected from national gas deregulation.

We are not natural gas producers nor are we experts in the field of gas availability. However, we firmly believe that the restoration of a free market will create development activities which will result in increased supply. At the same time the increased market price will restrain the growth of consumption and shift the gas usage to more efficient end uses. The supply-demand equation should balance at a much higher level than we shall experience under the current regulatory position.

We in the steel industry urge the federal government to act in concert both legislatively and administratively to help the industrial sector get through future years as smoothly as possible. This will allow the jobs of American workers to be preserved and help continue our economic recovery.

For the long range well-being of the country, we urge the passage of legislation that will create the necessary climate for increased incentives for drilling to increase natural gas supply and then permit the free market-place to determine the end use.

We appreciate the opportunity to present our views on this most important subject this morning.

Thank you.

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Statement Before The

Energy and Power Subcommittee

Committee on Interstate and Foreign Commerce

of

The House of Representatives

on

Long-Term Solutions to the Natural Gas Supply Problem

Presented on Behalf of

the American Paper Institute

by

Abbott A. Lane, Jr.
Westvaco Corporation

January 30, 1976

INTRODUCTION:

I am Abbott A. Lane, Jr., Manager, Traffic & Purchasing, Westvaco Corporation. My duties include responsibility for purchase of raw materials and fuel for the Corporation. I am here today representing the American Paper Institute, the national trade association of the pulp, paper and paperboard industry of whose Raw Materials and Energy Committee I am a member.

The pulp and paper industry is among the ten largest in the U.S., with manufacturing plants in virtually every state, employing more than 700,000 people whose wages, salaries and benefits exceeded $8.5 billion in 1974 when sales totaled approximately $32.8 billion.

I appreciate this opportunity to express, on behalf of the pulp, paper and paperboard industry, our views on the legislative requirements to deal with rising natural gas curtailments in interstate pipelines.

The Pulp, Paper and Paperboard Industry is One of the Major Manufacturing Consumers of Fuel and Energy, Including Natural Gas:

While the U.S. pulp, paper and paperboard industry is the fourth largest manufacturing consumer of fuel and energy and the sixth largest manufacturing consumer of natural gas in the nation, natural gas meets almost one-third of the industry's purchased energy needs. Consequently, we are vitally concerned with curtailments of natural gas service and federal measures to stabilize supply.

The American Paper Institute has been conducting surveys of the industry's fuel and energy consumption since 1971. It is of interest to note that in that year, natural gas provided about 25.8 percent of total energy requirements, compared to 18.3 percent today (see Diagram I). At the same time, while fuel oils met about 20 percent of the industry's total energy needs in 1971, this energy source contributed 24.6 percent during the first six months of 1975. We believe this substitution of oil for gas to be closely linked to the year-by-year increase in natural gas curtailments to industry since 1971.

It is also important to note that the industry obtained 42.5 percent of its energy requirements from self-generated sources such as spent pulping liquors, bark and hogged fuels during the first six months of 1975, so that natural gas provided almost 32 percent of total purchased requirements, compared to 40.2 percent in 1971.

The American Paper Institute Has Completed a Detailed Survey of Natural Gas Consumption in the U. S. Pulp and Paper Industry:

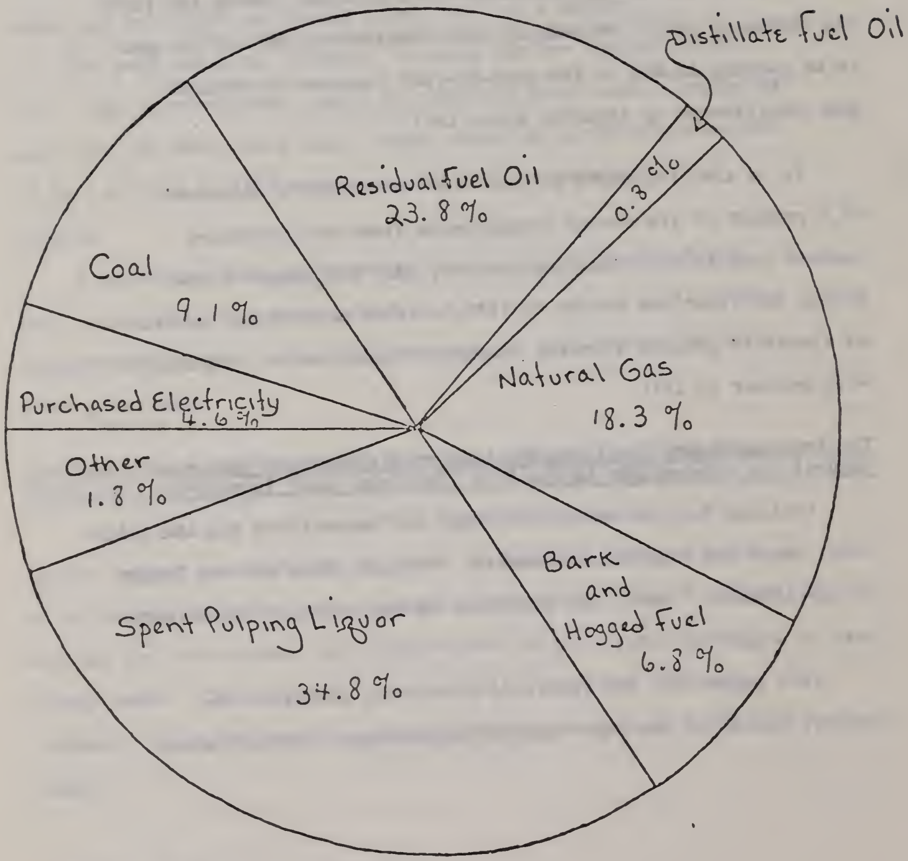
Included for the record is a copy of "Natural Gas and the U.S. Pulp, Paper and Paperboard Industry: Sources, Uses and the Impact of Curtailments," which was published by the American Paper Institute in August of 1975.

This report was the result of a detailed survey of the primary sector of the paper and allied products industry, where

DIAGRAM I

U.S. PULP AND PAPER INDUSTRY
SOURCES OF ENERGY

FIRST SIX MONTHS, 1975



Source: American Paper Institutue

the major portion of natural gas is consumed. Converting operations (those which manufacture such products as envelopes, boxes, and bags) were not surveyed.

Among the significant findings of this study are:

1) The U.S. pulp, paper and paperboard industry had 45 percent of its firm contract natural gas requirements curtailed last winter. This level of curtailments would have been greater, but for the general downturn in economic activity and unseasonably warm weather during that period.
2) While between 75 and 80 percent of natural gas consumed by the industry is used as boiler fuel, most of the remainder is used in various direct heat applications (e.g. paper drying and coating, lime kiln operations, pilot flames) where the substitution of alternate fuels is difficult and often impossible with available equipment.
3) By planning ahead, almost all operations indicated that they expected to avoid significant production and employment losses this winter under existing pipeline forecasts of curtailment levels.

The Pulp, Paper and Paperboard Industry Has Taken a Number of Steps to Insulate Itself from Natural Gas Supply Fluctuations:

Segments of the pulp, paper and paperboard industry began to feel the impact of natural gas curtailments as early as 1971. And since curtailments levels have risen, most companies have increased their mills' capabilities of substituting oil or propane for natural gas.

Where natural gas is used as a boiler fuel, this is relatively straightforward, but requires the installation of oil storage facilities, in-plant pipelines, fuel-heating systems, special fuel firing adaptations and perhaps, additional pollution control equipment.

In the case of direct heat applications, however, petroleum and propane may not always be usable as a substitute. And where they are, other difficulties arise, such as local opposition to the construction of above-ground propane storage tanks.

Of course, all of these conversions and precautions require capital expenditures. These expenditures are, by their very nature, inflationary to the general economy, especially where fuel switching capability makes for duplication.

At the same time, the substantial cost of taking these precautionary steps has forced many companies to take calculated risks based upon their best assessment of future levels of gas curtailments. It would be uneconomic to try to cover the entire risk of production losses.

Consequently, if pulp, paper and paperboard companies have not assessed the situation for this winter and future winters as well as they have in the past, production losses are a possibility.

Of even greater concern, the pulp and paper industry is an integral part of the larger U.S. economy. It is itself utterly dependent on a myriad of energy dependent suppliers of raw materials and equipment and, of course, our products are used in every sector of the economy. Therefore, the impact of natural gas curtailments will almost inevitably have a multiplied impact on the pulp and paper industry, and these dislocations could in turn be broadly passed on to the entire nation.

The Price Regulation of Interstate Natural Gas Has Created An Uncertain Supply Situation:

A recently completed Federal Energy Administration study has shown how the price regulation of interstate natural gas has created an uncertain supply situation. While the average annual net reserve additions to interstate pipelines grew by 11.4 trillion cubic feet (TCF) compared to 5.6 TCF for intrastate pipelines between 1964 and 1969, this situation was reversed between 1970 and 1973 when annual additions increased by only 0.7 TCF for interstate compared to 8.4 TCF for intrastate pipelines. This phenomenon is the direct result of maintaining interstate natural gas prices below what would be their actual free market level.

For some, the sense of urgency over natural gas legislation has waned since the recent FEA announcement that the gas shortfall this winter will not be as great as had been expected.

This adjusted forecast, however, has not reduced the level of concern in the pulp, paper and paperboard industry, which has experienced growing curtailments since 1971, and expects this pattern to continue in the years ahead.

Price Decontrol of New Natural Gas, As Provided for in S.2310 and Krueger-Broyhill, is the Best Solution to Growing Shortages:

We support the natural gas pricing provisions of S.2310 and the Krueger-Broyhill substitute to H.R. 9464 because we believe that price deregulation of new natural gas is the best course to follow to deal with natural gas shortages. It will simultaneously:

1) Stimulate new gas sources to the extent gas can be found;
2) Spur development of alternative sources; and
3) Induce more conservation as higher gas prices ultimately reach the consumer.

In the broadest context, price regulation has never worked and it can't possibly work in the natural gas situation where price controls are placed only on one of many competing energy sources. At the present time, oil and coal prices are well above those for equivalent energy values of interstate natural gas. Natural gas prices, at the wellhead, ought to float freely with those of all other sources of energy (except in natural monopoly situations such as pipeline gas delivery), to ensure the most economic usage of this premium fuel.

At the same time, however, we are concerned that the incremental pricing provisions of S.2310 would unnecessarily limit the benefits of "new" natural gas price decontrol.

Under incremental pricing, interstate pipelines would be required to file separate tariffs reflecting the breakdown of "old" and "new" gas, and give first priority for sales of old natural gas to distributing companies for service to residential and other small consumers.

There are many reasons why incremental pricing provisions do not belong in price deregulation legislation. Among these, incremental pricing would:

1) Make the financing of substitute natural gas projects more difficult, or perhaps impossible.
2) Create administrative chaos throughout regulatory administration.
3) Seriously reduce the flexibility of local, state and federal regulatory agencies in determining and implementing policies which are in the overall public interest.

But the most striking aspect of the proposed incremental pricing provision is its apparent disregard of the need for natural gas conservation by all users. On this vital subject, we cannot identify any rationale for incremental pricing.

For example, if incremental pricing is aimed at minimizing the cost impact of higher "new" natural gas prices on homeowners and the general public, it should be recognized that while those consumers who now enjoy natural gas service might benefit, they would have no incentive to reduce their consumption. As a result, other residential consumers would be denied natural gas service and consequently forced to rely on much higher-priced imported fuel oil. In essence, why should the gas-consuming public be favored over the oil and coal-consuming public?

We are also concerned that the inflationary consequences of incremental pricing have not been fully examined. The American Paper Institute Energy Monitoring System indicates that the pulp, paper and paperboard industry managed to reduce its purchased energy use per unit of output by some 9 percent in October and November, 1975, compared to the same period in 1972.

With so much already accomplished and further reductions requiring time and capital, there cannot be as rapid a reduction in energy use per unit of output as in the past and the cost pressures of incremental pricing would have to be passed on to the general public.

Residential consumers of natural gas, on the other hand, have had little incentive to reduce their natural gas consumption, beyond exhortations from government during periods of curtailments.

In the long run, it will take price incentives to induce residential consumers to share the burden of energy conservation.

Finally, it may seem unusual to the Subcommittee that a large consumer of natural gas, such as the pulp, paper and paperboard industry would support legislation which would increase its costs. Over and above our abiding faith in the efficacy of the free market, we believe that the costs of doing business in the face of the uncertainty of natural gas curtailments and the inevitability of production and employment losses are bound to be much greater than those associated with decontrol of "new" natural gas prices.

As FEA Administrator Frank Zarb recently pointed out, U.S. gas production is continuing to decline at a six percent annual rate. Current proved reserves excluding Alaska, stand at the lowest level since 1952.

Whether or not natural gas curtailments cause serious economic dislocation this winter, or next, the long run problem is worsening and no coherent federal policy has been developed to deal with it.

On behalf of the pulp, paper and paperboard industry, I therefore urge the Subcommittee to work towards the early price decontrol of "new" natural gas as the centerpiece of a federal policy.

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January 30, 1976

STATEMENT OF THOMAS J. DEVINE

before the
Committee on Interstate and Foreign Commerce
Subcommittee on Energy and Power
U.S. House of Representatives

on

"LONG-TERM SOLUTIONS TO THE
NATURAL GAS SUPPLY SHORTAGE"

Mr. Chairman, members of the Committee, my name is Thomas J. Devine. I am Vice President of Celanese Corporation, and appear before you today as a representative of PEG, the Petrochemical Energy Group, which is comprised of twenty-three independent petrochemical companies. 1/

Virtually all petrochemicals are derived from crude oil and natural gas, including the liquids and liquifiables found in the natural gas stream. These are our raw materials which we use to make a myriad of consumer and industrial products. 2/ Access to adequate supplies of these raw materials, which we call "feedstocks," is essential for the continued operations of our

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1/ Borg-Warner Chemicals; Celanese Corporation; Chemplex Company; Dart Industries, Inc.; The Dow Chemical Company; E. I. du Pont de Nemours and Co., Inc.; Ethyl Corporation; Firestone Tire & Rubber Company; Foster Grant Company, Inc.; The B. F. Goodrich Company; Goodyear Tire & Rubber Company; Hercules Incorporated; Monsanto Company; National Distillers & Chemical Corporation; Nipro, Inc.; Olin Corporation; Oxirane Corporation; Petro-Tex Chemical Corporation; PPG Industries, Inc.; Publicker Industries, Inc.; Rohm and Haas Company; Texas Eastman Company, Division of Eastman Kodak Company; Union Carbide Corporation.

2/ See Table I, "Petrochemical Industry Flow Sheet" and Table II, "End-Use Patterns for Key Final Products of the Petrochemical Industry."

production facilities. In turn, the operation of our plants is vital to the health of the national economy, and the well-being of all our nation's citizens. I would like to emphasize at the outset that there are simply no feasible substitutes for our existing production facilities, 3/ and even for new plants it will neither be economically or technically feasible, in the foreseeable future, to utilize coal as a substitute feedstock.

Our interest, which necessarily coincides with that of the consuming public, is in assuring the availability of the raw materials, including natural gas and natural gas liquids 4/, on which our industry depends. A brief consideration of the products derived from natural gas and natural gas liquids leaves little question that petrochemical companies play a crucial role in our economy. 5/ Those products include petrochemical-based fertilizers 6/ and pesticides, synthetic rubber, paints and pharmaceuticals,

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3/ See, An Analysis of the Impacts of the Projected Natural Gas Curtailments for the Winter 1975-1976, Office of Technology Assessment, United States Congress (November 1975) p. 14.

4/ The petrochemical industry uses about ten percent of the natural gas consumed in the United States, and natural gas provides approximately 25% of the industry's total feedstock requirements. See Table III, "1974 Estimated Feedstock and Fuel Consumption for Chemicals."

5/ The importance of our industry to the economy is illustrated by its size. The U.S. petrochemical industry currently employs more than 390,000 people in 1,900 plants with annual sales in excess of $40 billion. As one measure of its size, the industry provides almost three times the jobs as the U.S. petroleum refining industry, nearly 50 percent more capital investment and more than double the value added. See Table IV, "Estimated 1974 Employment in the Chemical Industry"; Table V, "Estimated 1974 Chemical Industry Sales"; Table VI, "1974 Value Added in the U.S. Petrochemical Industry"; and Table VII, "The U.S. Petrochemical Industry (1972)."

6/ On September 16, 1975, the U.S.D.A. estimated that supplies of ammonia-based fertilizers are expected to be below that of 1974-1975. Ammonia plants served by interstate pipelines account for an estimated 64 percent of total annual anhydrous ammonia capacity. See USDA News Release dated September 16, 1975. See also, An Analysis of the Impacts of the Projected Natural Gas Curtailments, Office of Technology Assessment, which states that the projected loss of ammonia production would translate into a loss of 4.8 million tons of grain, or about 2% of the total U.S. grain production in 1974. p. 10.

plastics, clothing and furniture, fibers, irrigation piping, adhesives, wire and home insulation and many other specialized and versatile products. It is the importance of natural gas and natural gas liquids to our industry which motivates our concern for an appropriate long-term legislative response to the growing natural gas shortage. It is the importance to the economy of all the essentials we produce which makes it incumbent upon this committee and this Congress to adopt the one policy which offers the best prospect of increasing critical natural gas supplies, namely deregulating the price of new natural gas.

My purpose in testifying today is to bring to this Committee's attention our belief in the essential correctness of legislation which would deregulate the price of new natural gas, and to urge the adoption of a long-term decontrol measure such as that approved by the Senate as S.2310, offered in modified form in this House by Representative Krueger as H.R. 11265. We have concluded that a continuation of the bankrupt policy of regulating the producer price of new natural gas in the interstate market will not arrest the decline in overall natural gas supplies, and that any extension of federal regulation and ceiling prices, such as that proposed in H.R. 9159, will decrease supplies of gas and gas liquids available to our industry. We are convinced that the natural gas supply, as well as the associated liquids on which we depend, will most likely increase, and price most likely stabilize, through the immediate deregulation of new natural gas.

Our concern is that of a consumer, since our principal relationships with oil and gas companies are as customers and as competitors of their petrochemical operations. We have placed our heavy investments in plants needed to meet the increasing demand for petrochemicals rather than in oil and gas exploration and development. As consumers, we are concerned first about supply. I do not mean to minimize our concern with cost, for domestic petrochemical plants cannot effectively compete 7/ with foreign

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7/ U.S. petrochemical companies do not dominate world markets. Of the top 10 chemical companies, only three are headquartered in the U.S. See Table VIII, "Major International Chemical Companies." The U.S. industry is facing increasing stiff competition in world markets. From 1971 to 1974, the number of new petrochemical projects in the world increased 45 percent. But only 10 percent of this construction is in the U.S.; the remainder is going on in developing nations plus Japan and Western Europe. See Table IX, "New Investments in Petrochemicals."

producers if our feedstock and fuel costs are substantially out of line with world markets. However, that concern means little unless necessary increments to supply are forthcoming, and that requires adequate incentives to encourage now increasingly more expensive exploration and development. 8/

The natural gas shortage is a reality, and strident rhetoric to the contrary will not alter this fact. 9/ While the FEA has recently revised downwards its curtailment figures to indicate that 21% rather than 23% of firm requirements will be curtailed in the present heating season, this in no way indicates that the gas shortage has been contrived, or is illusory. The revised figures resulted largely from unseasonably good weather which has lessened the demand for natural gas by residential and commercial customers. As FEA Deputy Administrator John A. Hill explained in a letter to the Washington Star, FEA does not claim ability to predict the weather and cannot precisely factor in the vagaries of nature into its computations. 10/ But even with the help of nature, the projected gas shortage remains at 1.0 Tcf, or an increase of 16% over last winter, in the 21 key states included in the FEA survey. 11/ Users of natural gas who are being curtailed can take only "cold" comfort from the knowledge that instead of receiving 314 billion cubic feet of gas less than last year, they will receive only 140 Bcf less. 12/

The fact remains that even the revised forecast of available supply does not obviate entirely the potential for

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8/ At the FPC currently-established well-head base price of approximately $.51 per Mcf, new natural gas is selling at the equivalent to oil of about $3.00 per barrel, or less than one-fourth the world market price of crude. Recent studies by the GAO, and FEA of the effect of deregulation of new natural gas have indicated that in 1985, with well-head prices of approximately $2.00 an Mcf, significant additional production could be expected over that projected under a continuation of the present regulatory scheme. Implications of Deregulating the Price of Natural Gas, GAO (January 14, 1976); Natural Gas Deregulation Analysis, Technical Report, FEA (January 23, 1976).

9/ Current Issues on Natural Gas Supply, National Association of Regulatory Utility Commissioners (December, 1975), p. 41.

10/ Washington Star, Jan. 7, 1976, p. A-16.

11/ Natural Gas Curtailments, 1975-76 Heating Season, Federal Energy Administration (October 1975).

12/ Federal Energy News Release, December 25, 1975. This December report represents an update of the data originally published in FEA's October report, Natural Gas Curtailments, 1975-76 Heating Season.

industrial shutdowns this winter. 13/ The situation thus remains critical, especially for states such as North Carolina and South Carolina which still face curtailment at rates in excess of 40 percent of requirements. 14/ The inescapable fact to be remembered is that curtailments are 1.03 Tcf, and that the downward revision does not indicate any reversal in the long-term decline of natural gas available for the interstate market. Reserve additions are down for the seventh year in a row. 15/ It will take approximately 170 million barrels of foreign oil at an approximate cost of $2.5 billion to replace this year's shortage. This is more than two-thirds of the $3.5 billion paid producers for all interstate natural gas during the twelve months ending September 1975. 16/

Since we are not very good prophets, we had better try to excel at preparation if we are to avoid the devastating consequences of more severe gas shortages certain to come in the future. 17/

I reiterate, our suppliers of gas are in curtailment; our suppliers of natural gas liquids, most of which come from gas wells and gas processing plants in both interstate and intrastate commerce, 18/ are unable to commit to supply us on a continuing basis, and new demands for these liquids attracted by artificially low regulated prices threaten not only our industry but the traditional residential and agricultural use of LPG.

13/ As FEA Administrator Frank Zarb pointed out in his recent testimony before this Committee, a severe cold spell in several states has already forced temporary industrial shutdowns and school closings, and several months of winter remain. (Statement of Frank G. Zarb before the Subcommittee on Energy and Power (January 23, 1976)).

14/ Chart, Comparison of October Reported and December Update For 21 States, Federal Energy News Release of December 25, 1975.

15/ FPC, "Gas Reserves," Release No. 21456 (June 6, 1975). The domestic reserves of natural gas peaked in 1967 at 289.3 Tcf and have declined in every year to a year-end figure in 1973 of 218.3 Tcf or a 25% decline. National Gas Survey, Vol. 1, Chapter I.

16/ FPC Release, Average Gas Prices for September 1975 (December 30, 1975).

17/ *Washington Star*, Editorial, December 12, 1975.

18/ For example, approximately two-thirds of U.S. propane production is extracted from natural gas, and approximately 25% of that propane has traditionally been used by the industry as feedstock. See, Table X, FEA Press Release T-74-436, "Projected 1974 Propane Demand and Consumption."

Continued regulation of the interstate gas market, or worse, an extension of regulation so as to preempt the intrastate natural gas market, as proposed in H.R. 9159, will not alleviate the present shortages, but instead is a prescription for ever worsening curtailments and serious economic dislocation. New price controls on intrastate gas can only impede the flow of additional gas into both the intra- and interstate markets. To accept as a "solution" to the problem of declining gas supplies continued and more pervasive regulation--the cause of our present dilemma--represents the height of folly. Both common sense and basic economics 19/ support the conclusion that the gas shortage is a result of regulatory policies discredited even by those who administer them. 20/

We are convinced that there is only one way to prevent increased shortages: deregulate the price of new natural gas. And doing it now provides the best chance of increasing supplies, decreasing non-essential demand and minimizing the economic impact to high priority consumers.

Additionally, I would urge consideration of a serious, but often overlooked, consequence of a failure to encourage increased supplies by deregulation. That consequence is the increased pressure for synthetic natural gas plants based on liquid hydrocarbons. 21/ Reliance on SNG to fill the gap created by declining natural gas supplies is neither rational nor wise public policy. Such SNG plants merely convert one clean fuel, including our feedstocks, into another fuel at increased cost to the consumer of from $2.50-4.50 per Mcf and at a loss of 10-20% of the energy used in converting a liquid into a gas. 22/ SNG plants not only frustrate conservation and

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19/ See summaries of independent studies by MacAvoy and Pindyck, "Alternate Regulatory Policies for Dealing with the Natural Gas Shortage," The Bell Journal of Economics and Management Science, (Autumn 1973) and by Robert B. Helms, Natural Gas Regulation: An Analysis of FPC Price Controls (July 1974), contained in Current Issues on Natural Gas Supply, NARUC (December 1975), at pp. 14-16.

20/ National Gas Survey, FPC Report, Vol. 1, pp. 3-4.

21/ See projections of increased reliance on SNG in Energy Through the Year 2000, Bureau of Mines, Dept. of Interior (December 1975), at p. 11.

22/ An Analysis of the Impact of the Projected Natural Gas Curtailments for the Winter 1975-76, Office of Technology Assessment, (November, 1975), p. 28. As a recent example, Columbia Gas of Ohio reported on January 13, 1976 to the Public Utilities Commission of Ohio that it was paying $4.20 per Mcf for SNG in its efforts to supply existing customers.

conversion goals, but our goal to reduce dependence on foreign oil. 23/ It is surely inconsistent to direct national policy in one area toward the goal of reducing reliance on oil imports, while failing to take corollary measures to prevent a developing trend toward SNG which would encourage a new potential demand for petroleum in excess of one million barrels a day. The four SNG plants presently in operation are consuming 26 percent as much LPG as the entire petrochemical industry consumed in 1972.

If natural gas is desired, it is far better and cheaper to increase supplies of natural gas through conventional drilling than to spend the millions to build manufacturing plants which divert, for example, propane needed for crop drying, rural heating and petrochemical feedstocks to the production of expensive SNG.

Unless Congress provides clear long-term incentives for the production of new natural gas supplies and discourages the diversion of our feedstocks to fuel use through SNG plants, the consequences could be something like this. A sustained reduction of only 15% in the production of basic petrochemicals, either because fuels or feedstocks are not available, would mean a loss of 1.8 million jobs in the U.S. and a loss of $65-70 billion in production value. 24/ This loss will be felt in the textile industry, for example in Maryland, Virginia, North Carolina, South Carolina and Georgia. It will be felt in the rubber industry in Ohio; the automobile business in Michigan and elsewhere; the farmbelt, and indeed, in every state. 25/

Facts exemplify better than words the damage that could occur.

Look at the textile industry in the Southeast. The textile apparel industry is the largest manufacturing employer in the United States, employing one out of every eight persons engaged in manufacturing. In South Carolina, 26/ textiles and apparel account for more than 50 percent of total employment. This industry was hard-hit by recession and reduced demand. It is reported that textile mill employment in January, 1975 dropped to 875,000 from 1,036,00 in January 1974.

23/ An Analysis of the Impacts of the Projected Natural Gas Curtailments for the Winter 1975-76, Office of Technology Assessment, United States Congress (November 1975) p. 11.

24/ See Table XI, "Summary - U.S. Petrochemical Industry Impact Analysis."

25/ See Table XII, "Geographical Distribution of the Petrochemical Industry in 1967" and "Estimated 1974 Regional Employment in the Chemical Industry."

26/ See Table XIII, "South Carolina Statistics."

Shortages of natural gas-derived petrochemicals could have the same impact. In 1973, man-made fibers accounted for 60 percent of the fibers used by U.S. textile mills. About 80 percent of all blankets and 93% of all carpets are now made from synthetic fibers. Using South Carolina as an example again, the more than $4 billion worth of textile mill products produced in that state in 1972 would be jeopardized.

It is important to know upon whom these mills rely for their raw materials. A direct link can be established between the vitality of this country's textile industry and the availability of oil and gas to the petrochemical industry. For example, the nylon used in South Carolina to make carpet and clothing can be traced to ammonia produced in Texas and Louisiana from natural gas. Polyester fibers, increasingly essential to these same uses nationwide, can be linked with the ethylene produced nationwide from natural gas liquids.

The same case can be made for the agricultural industry--or the consumer product industries located in New England, the Mid-Atlantic states or the Midwest. For example, in 1972, New England and the Middle Atlantic states, a long way from the oil and gas producing regions of the country, accounted for 19 percent of total U.S. petrochemical-based product shipments. 27/ Plastic fabrication industries concentrated in the Northeast are dependent upon petrochemicals to make telephones, construction materials, packaging, safety glass, furniture and appliances.

The automobile industry's increasing dependence upon synthetic rubber and plastics to achieve lower weight, better performance automobiles could be jeopardized. The average 1975 automobile manufactured in the U.S. contains more than 300 pounds of petrochemicals. It is estimated that almost 20 percent of all petrochemicals derived in the U.S. from crude oil and natural gas liquids were required to produce the new cars sold in 1973 and to keep the old ones running.

International trade is also involved. In 1974, the U.S. petrochemical industry contributed nearly $3.7 billion of exports toward our balance of trade. 28/

We believe that immediate and permanent deregulation of new natural gas prices provides the best chance of solving the

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27/ See Table XIV, "The Petrochemical Industry in the New England and Middle Atlantic States."

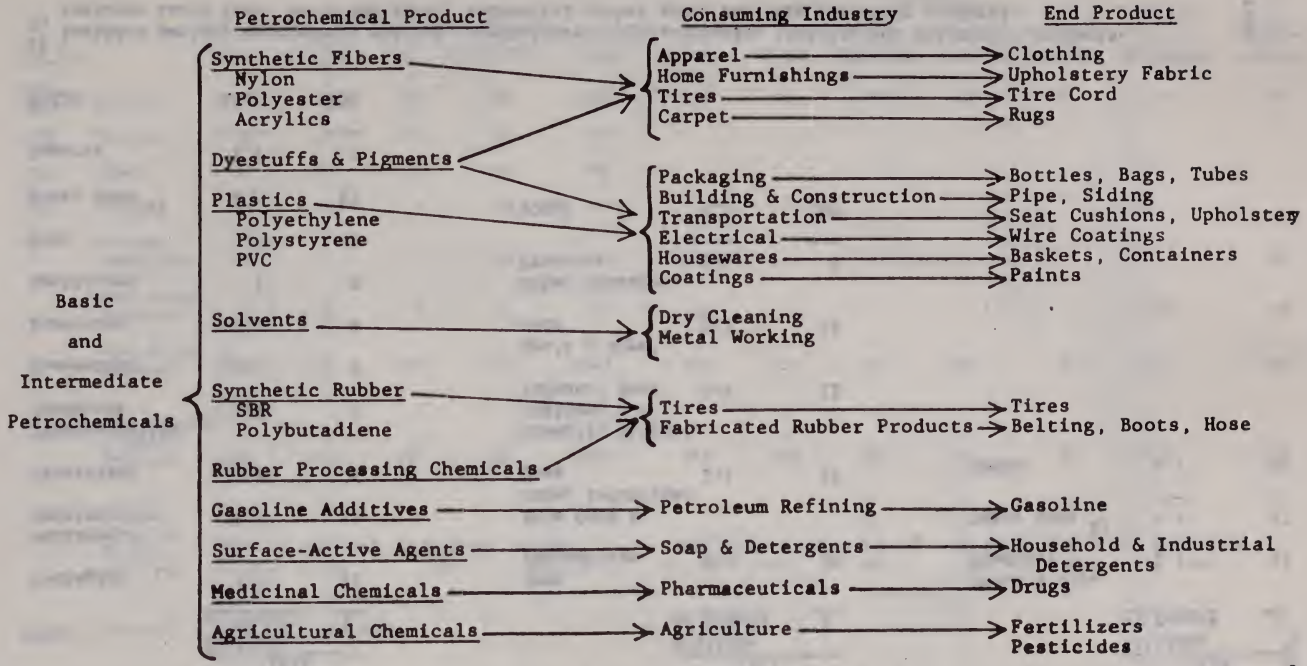
28/ See Table XV, "U.S. Balance of Trade in Petrochemicals."

problems confronting the nation as a result of declining natural gas supplies. Public opinion polls demonstrate that the American people have recognized and support the necessity for deregulation.[29/] We urge this Congress to respond to economic reality and enlightened public opinion.

[29/] The public is out in front of the Congress in its understanding of this issue, approving the deregulation of new natural gas by the substantial margin of 44 percent in favor, with only 26 percent opposed as measured by the most recent Harris Survey conducted in November of 1975.

Table I

PETROCHEMICAL INDUSTRY FLOW SHEET



END-USE PATTERNS FOR KEY FINAL PRODUCTS OF THE PETROCHEMICAL INDUSTRY

	Plastics 1972 Billions of Pounds	Plastics 1972 %
Packaging	5.2	21
Building & Construction	4.5	19
Electrical	1.4	6
Transportation Equipment	1.3	5
Housewares	1.2	5
Furniture	1.0	4
Appliances	.7	3
Toys	.7	3
Other Uses [1]	6.6	27
Exports	1.7	7
TOTAL	24.3	100

	Synthetic Fibers 1971 Billions of Pounds	Synthetic Fibers 1971 %
Home Furnishings	1.3	30
Tire Cord & Other Industrial Uses	1.1	27
Women's, Misses', Children's & Infants' Wear	0.9	21
Men's & Boys' Wear	0.7	16
Other Consumer Products	0.3	6
TOTAL	4.3	100

	Synthetic Rubber 1970 Billions of Pounds	Synthetic Rubber 1970 %
Tires & Tire Products	2.7	63
Other Uses [2]	1.6	37
TOTAL	4.3	100

1) Includes marine, sportswear, medical, agriculture, signs, luggage, textile, and disposable products.
2) Includes latex foam, boots and shoes, mechanical rubber goods and wire and cable products.

Sources: Modern Plastics Magazine, Jan. 1973; Textile Organon, Jan. 1970 and 1972; SRI's Chemical Economics Handbook; and Arthur D. Little, Inc., estimates.

Table II

Table II

1974 ESTIMATED FEEDSTOCK AND FUEL CONSUMPTION FOR CHEMICALS

(trillion BTU)

		Fuels					Feedstocks						
SIC No.		Natural Gas	Distillate & Resid.	Coal	Purchased Electricity	Fuel Total	Natural Gas	Ethane	Propane/ Propylene	Butane/ Butylene	B-P Mix & Isobutane	Heavy Liquids Feedstocks	Feedstock Total
2865 2869	} Organics	531	63	146	282	1022	139	333	298	221	39	730	1760
2821	Plastics	62	39	46	91	238							
2824	Fibers	57	35	72	70	234							
2822	Rubber	52	1	7	23	83							
2873	Nitrogen Fertilizer	252	-	-	15	267	371						371
	Other Petro-chemicals	77	14	2	6	99	57					81	138
	Total Petro-chemicals	1031	152	273	487	1943	567	333	298	221	39	811	2269
28	Total Chemical & Allied Products	1598	237	503	1195	3533	567	333	298	221	39	811	2269
	Conversion Factors -BTU per:	1031 cu. ft.	6.084×10^6 bbl.	23.96×10^6 ton	10,479 kwh		1031 cu. ft.	2.67×10^6 bbl.	3.5×10^6 bbl.	4.02×10^6 bbl.	3.86×10^6 bbl.	5.411×10^6 bbl.	

Source: Arthur D. Little, Inc., estimates.

Table IV

ESTIMATED 1974 EMPLOYMENT IN THE CHEMICAL INDUSTRY

(000)

	Manufacturing Employment	Total Employment
Chemical & Allied Products	855	1063
Inorganic Chemicals	96	165
Organic Chemicals	130	168
Total Industrial Chemicals	226	333
Petrochemicals		
Organic Chemicals		
Dyes	12	14
Pigments	4	5
Cyclic Intermediates	12	14
Industrial Organics	102	135
Subtotal	130	168
Plastics & Resins	59	64
Synthetic Fibers	80	108
Elastomers	12	15
Surface Active Agents	7	9
Carbon Black	3	4
Nitrogen Fertilizer	10	11
Medicinals	9	11
Total	310	390

Sources: Manufacturing employment based on 1972 Census of Manufactures and Arthur D. Little, Inc., estimates.

Total employment based on U.S. Department of Labor, Bureau of Labor Statistics, Employment and Earnings, December 1974, and Arthur D. Little, Inc., estimates.

Table V

ESTIMATED 1974 CHEMICAL INDUSTRY SALES

(millions of dollars)

		Value of Shipments	
		1972	1974
Chemical & Allied Products		57,062	82,000
Industrial Chemicals			
Inorganic		5,927	8,000
Organic		11,036	21,300
		16,963	29,300
trochemicals			
Organic Chemicals			
Cyclic Intermediates	2865	2,002	6,000
Miscellaneous Organics	2869	9,034	15,300
Plastics	2821	4,497	8,500
Fibers	2824	3,675	4,400
Rubber	2822	1,089	2,150
Surface Active Agents	2843	452	600
Carbon Black	2895	227	350
Nitrogen Fertilizer	2873	837	2,700
Medicinals	2833	566	800
		22,379	40,800

Source: U.S. Department of Commerce 1972 Census of Manufactures and Arthur D. Little, Inc., estimates.

Table VI

1974 VALUE ADDED IN THE U.S. PETROCHEMICAL INDUSTRY

(millions of dollars)

Sector	Total Sales	Cost of Materials and Supplies *	Value Added
Cyclic Intermediates	6,000	2,040	3,960
Organic Chemicals	15,300	7,200	8,100
Plastics	8,500	4,800	3,700
Fibers	4,400	2,925	1,475
Rubber	2,150	1,350	800
Surface Active Agents	600	465	135
Carbon Black	350	155	195
Nitrogen Fertilizer	2,700	540	2,160
Medicinals	800	400	400
	40,800	19,875	20,925

Gross Industry Sales	$40,800
Intra-Sector Sales	-5,275
Intra-Industry Sales	-8,840
Net Industry Sales	$26,685
Value Added	-20,925
Estimated Net Cost of Raw Materials and Supplies	$ 5,760

* Includes intra-sector and intra-petrochemical industry purchases.

Source: Arthur D. Little, Inc., estimates.

Table VII

THE U.S. PETROCHEMICAL INDUSTRY

(1972)

		Employment (000)	Value Added ($ MM)	Capital Investment ($ MM)
2869	Organic Chemicals	100	4,922	565
2865	Cyclic Intermediates	28	914	152
2821	Plastics and Resins	55	2,192	279
2822	Synthetic Rubber	12	487	34
2824	Synthetic Fibers	78	2,084	369
2843	Surface Active Agents	7	204	21
28411	Detergents	5	376	11
2895	Carbon Black	3	138	12
	Ammonia	5	323	20
	Total Petrochemical	293	11,640	1,463
By Comparison:				
2911	Petroleum Refining	101	4,627	1,067

Sources: U.S. Department of Commerce, 1972 Census of Manufactures; and Arthur D. Little, Inc., estimates.

Table VIII

MAJOR INTERNATIONAL CHEMICAL COMPANY SALES - 1973

Company	Total Sales ($ billion)
BASF (Germany)	5.9
Hoechst (Germany)	5.7
Bayer (Germany)	5.4
Du Pont (United States)	5.3
ICI (United Kingdom)	5.2
Montedison (Italy)	4.3
UCC (United States)	3.9
Pechiney-Ugine Kuhlmann (France)	3.6
AKZO (Holland)	3.6
Dow (United States)	3.1

Sources: C&EN, June 3, 1974, page 30; March 18, 1974, page 10; and August 12, 1974, page 13; Chemical Week, June 26, 1974, page 34.

Table IX

NEW INVESTMENT IN THE PETROCHEMICAL INDUSTRY

NUMBER OF ACTIVE NEW PLANT CONSTRUCTION PROJECTS

	1971		1974	
	Number	%	Number	%
United States	41	8.5	76	10.8
Western Europe	204	42.2	164	23.4
Japan	56	11.6	50	7.1
Developing Countries	183	37.7	413	58.7
Total	484	100.0	703	100.0

Source: Oil & Gas Journal, March 11, 1974, page 80.

Table X

Figure 2

Projected 1974 Propane Demand and Consumption
(Million Barrels)

Category	Demand (1)	Consumption	Constraint
Residential	196	164	Price and Allocation
Internal Combustion	34	27	Allocation
Petrochemical	77	84	Note (2)
Miscellaneous	9	9	None
Industrial-"Clean Fuel"	13	12	Allocation
- Refinery Fuel	13	12	None
- Meet curtailment	15	12	Note (3)
Utility Gas	8	7	Allocation
SNG	9	7	Allocation
Export	5	5	Note (4)
Total	375	339	

(1) Projected demand at retail delivered price of 15¢/gal.

(2) Demand as used here represents "Disappearance From Primary Inventory". A special provision provides an opportunity to build up depleted inventories. Thus, purchases for inventory show up as consumption.

(3) Assumes FEA can allocate to users only amounts actually justified.

(4) Export is limited by Department of Commerce to the base period amount.

ATCH 2 to T-74-436

Table XI

SUMMARY

U.S. PETROCHEMICAL INDUSTRY IMPACT ANALYSIS

The current shortages of oil and gas in the United States have forced the Federal Government to implement a Mandatory Fuel Allocation Program, a Mandatory Allocation Program for Propane, and to supervise an expanding level of curtailments in natural gas supplies to interstate pipelines. These shortages will have a significant impact on the whole economy and the petrochemical industry as a major consumer of oil and gas hydrocarbons will be directly affected. However, the impact on this industry and its customers will be significantly greater than on other industries because these hydrocarbons are used not only as fuel but also as the primary raw materials or feedstocks for this business.

As a result of the current shortages, it is not unrealistic to expect that petrochemical production will decline in the near future. To assess the impact of a decline in petrochemical production on the nation's economy as a whole, the Petrochemical Energy Group (PEG) asked Arthur D. Little, Inc. (ADL) to develop an estimate of the effect of a 15% decline in the organic chemicals industry on consuming industries. Through the use of input-output economic analysis, ADL estimates that a sustained 15% reduction in the output of the organic chemicals industry could result in a loss of 1.6 to 1.8 million jobs in consuming industries and a loss of domestic production value of $65-70 billion annually.

While our analysis assumes a decline in production of 15%, it is difficult at this time to anticipate just how extensive a decline will actually result from the current allocation and curtailment programs. Should these programs not provide for the feedstock and process fuel needs of the petrochemical industry, its output will be reduced with the effects cascading throughout the economy.

Note: The full text of this report can be obtained from the Petrochemical Energy Group, Suite 335, 1701 Pennsylvania Avenue, N.W., Washington, D. C. 20006

November, 1973

Table XII-1.

GEOGRAPHICAL DISTRIBUTION OF THE PETROCHEMICAL INDUSTRY IN 1967

	Employment		Value Added	
	Number 000's	% of Total	$ MM	% of Total
New England	14	5	266	3
Middle Atlantic	57	21	1226	15
South Atlantic	72	26	2049	25
East North Central	36	13	1042	13
East South Central	27	10	819	10
West North Central	7	3	212	3
West South Central	45	16	2200	27
Louisiana	7	3	295	4
Texas	32	12	1622	20
Subtotal	39	15	1917	24
Mountain	1	1	28	neg
Pacific	15	5	372	4
TOTAL	274	100	8214	100

Source: 1967 Census of Manufactures and Arthur D. Little, Inc., estimates.

Table XII-2

ESTIMATED 1974 REGIONAL EMPLOYMENT IN THE CHEMICAL INDUSTRY

(thousands of employees)

	Total Chemical and Allied Products		Industrial Chemicals				Total Petrochemicals	
			Inorganic		Organic			
	Number	% of Total	Number	% of Total	Number	% of Total	Number	% of Total
New England	33	4	2	2	7	5	26	8
Middle Atlantic	203	24	17	18	34	26	47	15
South Atlantic	163	19	15	15	19	15	83	27
East North Central	166	20	22	23	14	11	34	11
East South Central	80	9	17	18	9	7	40	13
West North Central	43	5	2	2	7	6	15	5
West South Central	85	10	16	17	36	28	56	18
Louisiana	22	2	6	6	6	7	14	5
Texas	58	7	6	6	26	18	38	12
Subtotal	80	9	12	12	32	25	52	17
Moutain	10	1	1	1	1	-	1	-
Pacific	72	8	4	4	3	2	8	3
Total	855	100	96	100	130	100	310	100

Source: 1972 Census of Manufactures and Arthur D. Little, Inc., estimates.

SOUTH CAROLINA STATISTICS

Table XIII
Page 1

Employment (Manufacturing) 1972[1]		No. of Employees	%
Textiles		143,000	41
Apparel		46,000	13
Chemicals - Plastic Materials & Synthetics	17,000		
Soaps, Cleaners, Surfactants	7,000		
Industrial Organics	1,000		
Other	2,000		
		27,000	8
All Other Manufacturing		129,000	38
		345,000	100%

Value Manufacturing Shipments - 1972[1]		Billions	%
Textile Mill Products		4.300	40
Chemicals - Plastic Materials & Synthetics	0.880		
Soaps, Cleaners, Surfactants	0.272		
Industrial Organics	0.101		
		1.374	13
Apparel		.740	8
All Other Manufacturing		4.246	40
		10.660	100%

Cost of Materials Purchased by Manufacturer[1]	$Billion
Textiles	2.576
Chemicals & Allied Products	.539
All Other	2.615
Total	5.730

Table XIII
Page 2

Value Added[1]	Billions	%
Textiles	1.717	35
Chemical	.801	16
Apparel	.352	7
Other	2.051	42
	4,921	100%

Payrolls (1st Qtr. 1972, annualized)[2]	No. of Employees	$ Million, Taxable Payroll
Synthetic Fibers	12,011	113
Plastic Materials	3,390	29
Industrial Chemicals	5,837	74
Agricultural Chemicals	794	4
Soaps, Cleaners	929	8
Paints & Allied Products	170	1
All Other	1,316	11
	24,447	240

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[1] Department of Commerce, 1972 Census (1971 data covered)

[2] Department of Commerce, County Business Patterns, 1972

Table XIV

THE PETROCHEMICAL INDUSTRY IN THE NEW ENGLAND AND MIDDLE ATLANTIC STATES

(% of national value of shipments)

– 1972 –

SIC	Industry Classification	New England	Middle Atlantic
2869	Organic Chemicals	2	16
2821	Plastics & Resins	10	20
2824	Synthetic Fibers	–	sm
2822	Elastomers	–	3
2843	Surface Active Agents	12	24
2895	Carbon Black	–	–
2873	Ammonia Only	–	2
2865	Cyclic Intermediates & Crudes	3	34
2841	Soaps & Detergents	5	17
	Percent of Total U.S. Petrochemical Shipments	4	15

Sources: 1972 Census of Manufactures, ADL estimates.

THE PETROCHEMICAL INDUSTRY IN THE NEW ENGLAND AND MIDDLE ATLANTIC STATES

(estimated value of shipments – millions of dollars)

– 1972 –

SIC	Industry Classification	Middle Atlantic	New England	National
2869	Organic Chemicals	1,450	210	9,035
2821	Plastics & Resins	890	440	4,495
2824	Synthetic Fibers	sm	–	3,675
2822	Elastomers	30	–	1,090
2843	Surface Active Agents	110	55	450
2895	Carbon Black	–	–	225
2873	Ammonia Only	10	–	515
2865	Cyclic Intermediates & Crudes	685	60	2,000
2841	Soaps & Detergents	570	170	3,330
	Total	3,745	935	24,815

Sources: 1972 Census of Manufactures, ADL estimates.

Table XV

U.S. BALANCE OF T.:ADE IN PETROCHEMICALS
(millions of dollars)

Trade Class		1965	1966	1967	1968	1969	1970	1971	1972	1973	Preliminary 1974
1. Dyes, Organic Pigments 531	Exports	31.4	34.7	31.7	35.1	32.7	43.0	44.6	53.2	85.8	117.0
	Imports	26.8	35.4	35.0	49.9	63.4	69.7	97.2	100.8	104.3	106.2
		4.6	-0.7	-3.3	-14.8	-30.7	-26.7	-52.6	-47.6	-18.5	10.8
2. Plastics (except cellulosics) 581	Exports	377.2	422.6	423.0	530.9	533.8	593.0	593.3	628.9	944.2	1483.9
	Imports	36.5	53.6	54.9	87.2	91.5	115.0	126.2	168.7	197.7	312.2
		340.7	369.0	368.1	443.7	442.3	478.0	467.1	460.2	746.5	1171.7
3. Synthetic Rubber 231.2	Exports	163.1	175.1	170.0	180.3	139.8	176.0	172.7	161.0	195.8	289.8
	Imports	19.0	23.6	20.7	29.3	37.8	42.2	56.3	53.6	64.3	79.2
		144.1	151.5	149.3	151.0	102.0	133.8	116.4	107.4	131.5	210.6
4. Detergents & Surface Active Agents 554.2	Exports	47.2	50.9	53.7	64.7	62.9	69.3	71.9	76.8	95.8	141.8
	Imports	2.5	3.5	4.5	5.5	7.0	7.2	8.4	9.2	12.7	22.4
		44.7	47.4	49.2	59.2	55.9	62.1	63.5	67.6	83.1	119.4
5. Carbon Black 513.27	Exports	26.7	28.8	26.1	15.4	12.6	14.0	14.9	10.4	17.2	27.9
	Imports	–	1.2	–	0.2	1.4	1.1	1.4	1.6	3.0	7.1
		26.7	27.6	26.1	15.2	11.2	12.9	13.5	8.8	14.2	20.8
6. Aromatics & Olefins 521	Exports	40.5	26.2	28.3	66.8	62.1	49.2	32.5	30.7	72.5	83.8
	Imports	1.2	–	1.1	–	–	–	–	–	0.5	1.1
		39.3	26.2	27.2	66.8	62.1	49.2	32.5	30.7	72.0	82.7
7. Synthetic Fibers	Exports	129.7	133.3	123.7	136.8	155.0	175.4	186.5	191.6	344.7	507.8
	Imports	46.7	54.7	56.6	98.8	85.5	201.3	340.1	297.9	248.0	178.0
		83.0	78.6	67.1	38.0	69.5	-25.9	-153.6	-106.3	96.7	329.8
8. Organic Chemicals* 512.500	Exports	759.0	802.7	864.8	992.3	1016.4	1183.2	1143.0	1219.5	1683.8	2846.0
	Imports	144.4	189.0	184.6	221.6	263.3	298.7	345.3	432.5	546.5	1098.5
		614.6	613.7	680.2	770.7	753.1	884.5	797.7	787.0	1137.3	1748.5
9. Ammonia	Exports	14.0	16.2	22.6	26.5	33.0	30.2	16.3	21.9	41.2	48.8
	Imports	9.5	15.3	19.1	18.6	20.7	20.7	20.5	17.0	15.5	52.5
		4.5	.9	3.5	7.9	12.3	9.5	-4.2	4.9	25.7	-3.7
Grand Total	Exports	1588.8	1690.5	1742.9	2048.8	2048.1	2333.3	2275.7	2394.0	3481.0	5545.8
	Imports	286.6	376.3	376.5	511.1	570.4	755.9	995.4	1081.3	1192.5	1857.2
		1302.2	1314.2	1366.4	1537.7	1477.7	1577.4	1280.3	1312.7	2288.5	3688.6

*See Appendix E-2 and E-3 for further breakdowns.

Source: U.S. Department of Commerce, Bureau of the Census FT 110, FT 135 U.S. Imports, and FT 410 U.S. Exports

Statement by

LEONARD H. FARMER
on behalf of the
GLASS CONTAINER MANUFACTURERS INSTITUTE

before the

HOUSE OF REPRESENTATIVES
Subcommittee on Energy and Power
Committee on Interstate and Foreign Commerce

January 30, 1976

Mr. Chairman and Members of the Subcommittee:

I appreciate this opportunity to appear before you today. I am Vice President and Director of Purchases for Owens-Illinois, Inc., a large manufacturer of packaging products with twenty-two glass container plants located throughout the United States. Owens-Illinois is a member company of the Glass Containers Manufacturers Institute (GCMI) upon whose behalf I am appearing today. The glass container industry as a whole consists of 98 member companies, operating 120 plants and employing approximately 77,000 people in the United States. The glass container industry is a consumer of natural gas, requiring gas for many critical manufacturing processes, and therefore is vitally interested in pending legislative proposals which could affect natural gas supplies.

My remarks are directed to the issues of deregulation of the wellhead price of new natural gas and the manner in which the cost of decontrolled new gas would be paid for by the consumers. Primarily with respect to the second issue, it is necessary to restate briefly certain facts concerning the background and present situation of natural gas distribution and pricing.

Residential and commercial demand for natural gas has been seasonal in nature, occurring principally during the winter heating season. Industrial users, on the other hand, generally have a uniform daily demand for natural gas which does not vary substantially from season to season. For this reason, pipelines and distribution companies historically have welcomed industrial loads as a means to balance their system demands. Because of its year-round nature, the presence of industrial loads has resulted in better utilization of pipeline facilities and lower overall costs for residential, commercial and industrial consumers alike.

In order to maintain summer demand while at the same time providing maximum system flexibility on peak demand days during the winter, distinctions developed in many parts of the country between firm supply contracts and interruptible contracts.

Under an interruptible contract, a company agreed that its service could be interrupted on short notice during periods of peak demand and it would have to make capital investments in alternate fuel facilities and utilize more expensive fuel during periods of curtailment. Since this type of service anticipated less than full availability of natural gas service and required additional capital and operating costs, the rate was lower than that charged for firm service. In addition to providing better pipeline utilization and system flexibility, the need for additional high cost pipeline and distribution system peaking capacity was obviated, thus resulting in lower costs for all ratepayers.

Another consideration is that generally pipelines receive their gas supplies from many sources with variations in price between those different sources. No one particular source has been earmarked for a particular customer. The total cost of acquiring gas to satisfy total demand has been averaged to develop a cost for the gas. Typically, rates for various classes of customers have been developed on a cost of service basis, so that each class of customers has paid on the basis of what it cost to serve that class of customers. In these cases the total cost of gas to supply the system has been averaged in developing those rates.

Over the years, natural gas has been a clean-burning, efficient, and economical fuel. Demand continued to grow at a high rate and, eventually, outstripped supply. Today, we are faced with general gas shortages throughout the nation. It has become necessary to allocate natural gas deliveries, and the FPC has established priorities under which residential and small commercial users are given the highest priorities. Under this system, industrial consumers are given lower priorities based on their "end use," i.e., the manner in which they use nautral gas. Because of supply deficiencies and regulation programs, much of the industrial load under both firm and interruptible contracts, has been substantially curtailed. Historically, the limited availability of natural gas service has been a justification for a lower rate.

In the past several years federal control of producer prices has become a factor in the shortage situation. Because of the shortage, uncontrolled producer prices in the intrastate systems increased at a much more rapid pace than FPC controlled producer prices for the interstate systems. One result has been that more available gas has been retained within the intrastate market and much less new gas has entered the interstate system. The disparity in producer prices between the interstate and intrastate markets constitutes an artificial factor which results in severe shortages in some parts of the country and relatively slight disruption in other parts of the country. All other things being equal, the interstate market cannot compete with the intrastate market.

In order to achieve a more equitable distribution of available gas and encourage exploration and development for new gas, this disparity in price between interstate and intrastate gas should be eliminated. There are two methods to eliminate that disparity in price. The first is to deregulate producer prices for new interstate gas. The second is to control both inter and intrastate producer prices. In my view, however, regulation of both inter and intrastate producer prices--aside from legal and constitutional questions--creates another problem of attempting to regulate all aspects of the natural gas industry from the wellhead down to the burner tip. The purpose of this control presumably would be to hold producer prices down, but demand for natural gas would continue at high levels. In short, an extensive allocation program, far beyond anything we have yet seen, would have to be implemented on both federal and state levels to allocate available gas between various types of customers. Under this scheme, low controlled prices would not serve as an incentive for increased exploration and development activity.

There also are adverse effects from deregulation. Decontrol of producer prices will result in substantial increases in the cost of gas going into the interstate system. If all natural gas were decontrolled, the result on our economy could be extremely disruptive. However, decontrol of only new gas permits the added cost to come through on a gradual basis and at the same time allows the interstate market to compete with the intrastate systems for new gas. It also establishes incentive for exploration and development to serve the interstate market.

Members of the glass container industry have considered these alternatives quite carefully. Owens-Illinois, which is the largest producer with plants located throughout the country, calculated the effect of deregulation on producer prices, and concluded that wellhead costs would increase by 45% by 1977, 100% by 1979, and 163% by 1981. Those calculations assumed decontrol effective January 1, 1976, and are measured from a 1975 base. Other assumptions are set forth on the attached schedule.

These are substantial cost increases for us to incur. Even with present prices, our cost of purchased energy exceeds our total corporate profits, and we are extremely conscious of energy utilization and costs in all aspects of our operations. In spite of this concern, we have concluded that producer prices for new interstate natural gas should be deregulated, that we and the economy would be better off in the long run to have the distribution of natural gas governed more by the market place rather than by government regulation, and that we are prepared to live with these very substantial cost increases because of the long-term benefits offered to the economy as a whole.

Once the issue of whether or not the wellhead price of new natural gas should be deregulated is resolved in favor of "deregulation," the next question is whether there should be some "tilt" or rate design mechanism employed to pass along proportionately greater costs to a certain class of users than would be imposed under traditional cost-of-service concepts. Under a variety of names such as "incremental" or "two-tier" pricing, it has been suggested that residential and certain commercial users be insulated from the economic effects of deregulating new natural gas production while industrial users should be required to bear the brunt of higher gas prices.

Logical questions presented by such proposals are first, is incremental or two-tiered pricing equitable, second, will such pricing actually insulate the residential consumer from the effects of deregulation and is it fair to all homeowners, third, will such proposals actually increase the inflationary aspects of decontrol, and fourth, are such proposals consistent with conservation objectives.

On the question of equity, it should be noted that existing shortages already have resulted in the imposition of extremely high additional costs on industry. In effect, service to industry has been changed to an interruptible basis, and industry must make capital additions to use other fuels, and absorb the higher cost of other fuels. The residential and small commercial user already has been favored by receiving a high priority of service.

It has been traditional to develop gas rates based on cost of service. These proposals would throw away years of federal and state precedent based on the premise that rates should fairly reflect costs, and instead have one segment of the economy underwrite cost of service to another class of customers. That is unfair.

To provide some idea of the magnitude of the impact on industry from incremental pricing, we can compare the cost impact of deregulation with the cost of deregulation combined with incremental pricing. The attached exhibit reflecting Owens-Illinois' calculations indicates that instead of wellhead prices increasing 45% by 1977, they will increase 108%, by 1979 they will increase 235% rather than 100%, and by 1981 the increase will be 378% rather than 163%.

These additional costs cannot simply be absorbed by industry. They will have to be reflected in higher prices, and in that sense the residential user will not be insulated from the effect of deregulation. Instead of paying a higher gas rate, he will pay higher prices, and all residential owners--not just gas users--will pay those higher prices. The person who heats with oil or coal will pay for his neighbor's gas in the prices he pays at the market, and the person who has an electrical home will be in especially bad shape. A lot of electricity still is generated with natural gas, and the electrical homeowner may pay much higher rates for his electricity, as well as higher prices.

It also must be recognized that these price increases will appear in all segments of raw material and finished product production, and the effect of adding these additional costs to the industrial sector will be multiplied. Additional energy costs will not just be passed through. Producers will expect returns based on their total costs, and at each stage in the manufacturing and distribution system there will be mark-ups on these added energy costs. That will exaggerate the inflationary aspects of decontrol.

It also must be anticipated that some businesses may not be able to absorb these additional costs. They may be marginal, or they may deliberately have located in areas undesirable from a freight or market viewpoint because of the availability of natural gas. Such businesses may have to close, and jobs will be lost.

Similarly, there are many industries in fierce and long-term competition in the market place. For one industry, natural gas may be a substantial cost factor. For another, it may have only a slight effect. Imposing these additional costs in this manner may affect the future of entire industries, and we earnestly submit that we should avoid this unnatural impact on our economy.

The Congress and the Administration are intensely interested in conservation of energy. Much attention has been directed to making everyone energy conscious and conservation minded. One of the methods of doing this has been to make people conscious of the cost of energy. Keeping residential gas rates artificially low would be inconsistent with conservation efforts, and in fact would be counterproductive.

In conclusion, I respectfully urge that producer prices for new interstate gas be decontrolled, that the cost of new gas be rolled into the total cost of gas for the system, and that each class of customers pay rates based on actual cost of service.

Thank you.

	OLD GAS			REGULATED NEW GAS				NEW GAS DEREGULATED				
YEAR	WELL HEAD	% TOTAL	TOTAL $ M	WELL HEAD	% TOTAL	TOTAL $ M	TOTAL OLD & NEW REGULATED	WELL HEAD	% TOTAL	TOTAL $ M	TOTAL OLD & NEW DEREG.	TOTAL NEW DEREG. ALLOCATED INCREMENT
1975	.42	100	21,000	.52	0	0	21,000	1.50	0	0	21,000	21,00
1976	.43	92.5	19,887	.54	7.5	2,025	21,912	1.80	7.5	6,750	26,637	33,38
1977	.44	85	18,700	.56	15	4,200	22,900	1.94	15	14,550	33,250	47,80
1978	.45	77.5	17,438	.58	22.5	6,525	23,963	2.10	22.5	23,625	41,063	64,68
1979	.46	70	16,100	.60	30	9,000	25,100	2.27	30	34,050	50,150	84,20
1980	.47	62.5	14,688	.62	37.5	11,625	26,313	2.45	37.5	45,938	50,626	106,564
1981	.48	55	13,200	.64	45	14,400	27,600	2.64	45	59,400	72,600	132,00

1. Assumed requirement remains constant at 50,000,000 Mcf annually.
2. New gas will replace old gas at 7.5% annually.
3. Regulated wellhead price will rise at 2¢ annually.
4. Deregulated price will escalate at a rate of 8% annually.
5. Industry uses 50% of total gas.

- Cont. on next page -

Cont.

PENALTY		WELLHEAD MCF COST UNDER INCREMENT DEREG.
DEREG. M $	DEREG. INCREMENT M $	
0	0	
4,725	11,475	.668
10,350	24,900	.956
17,100	40,725	1.294
25,050	59,100	1.684
34,313	80,251	2.131
45,000	104,400	2.640

STATEMENT OF DAVID S. SCHWARTZ*
MICHIGAN STATE UNIVERSITY

Hearings Before The
Subcommittee on Energy and Power
Committee on Interstate and Foreign Commerce
U. S. House of Representatives

January 30, 1976

Initially, I wish to express my thanks to the Chairman and members of the Subcommittee for giving me the opportunity to appear before you to present testimony on S. 2310 (Senators Pearson-Bentsen), H. R. 11265 (Congressman Krueger and others), and H. R. 9159 (Congressman Fraser and others). The focus of my presentation will relate to the long term aspects of the bills, that is, Title II or the permanent amendments to the Natural Gas Act of both the Krueger and Pearson-Bentsen bills. In this regard, it is essential that the issue of continued regulation (hopefully something superior to the perpetuation of the status quo) or deregulation of the natural gas producing industry will be considered in the light of the natural gas producer market and the question of adequate supply elicitation. Meaningful evaluation of these bills must be addressed within the context of industrial organization.

Introduction

While my testimony concerns the permanent aspects of the amendments to the Natural Gas Act, nonetheless, significant insight can be obtained in briefly reviewing the initial basis for the emergency aspects of the bills. In the summer and fall of 1975, the Federal Power Commission and the Federal Energy Administration released figures concerning curtailments for the 1975-76 winter period and for the ensuing year indicating very sharp curtailment which would lead to massive unemployment and a serious slow down of the economy. These curtailment estimates (1.3 trillion cubic feet for the winter) alarmed the country and the Congress and precipitated both short term emergency legislation as well as efforts for permanent deregulation of well head prices of natural gas.

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* The views and opinions expressed in this statement are entirely personal and are submitted in an individual capacity.

The subsequent reports by the General Accounting Office and Congress's Office of Technology Assessment challenged these stark predictions and indicated that available alternative fuels as well as intrastate natural gas supplies would be adequate for this winter's needs with a few possible exceptions. In fact the deficiency was estimated to be one-fourth of the FPC-FEA projections. What is the meaning behind the Administration's efforts to exaggerate the supply picture and panic the Congress? Obviously, it is an effort to obtain precipitous action based upon the "supposed" dire consequences if we continue meaningful short-term or any regulation. It is essential that the Congress sense this effort to pressure for immediate action without a full evaluation of the consequences for the consuming public.

Before evaluating the legislation cited, it is critical that the question of deregulation or continued regulation is appropriately postured with respect to the question of workable competition and future supply prospects.

The Natural Gas Producer Market

I have previously testified before this Committee (the latest was November 11, 1975) and other Congressional Committees as to the monopolistic characteristics of the natural gas producer market. I will not reiterate the empirical evidence that I have introduced into the record previously which has led me to conclude that this market is not workably competitive.

In essence, an examination of the buying side of the market indicates that all major interstate pipeline companies have producing affiliates and that they are not exclusively buyers, but sellers of natural gas as well. In addition, the pipelines affiliates are involved in joint ventures with the major producers so that the prospects for arm's length bargaining are considerably blunted because of these partnerships. Lastly, the utilization of the purchase gas adjustment clauses permit the pipelines to pass through automatically any increase in wellhead prices. Obviously we can expect very little countervailing power on the part of the pipelines in bargaining with producers, because of their self-interest as producers of natural gas.

In assessing the seller side of the market, we find that extensive interties, interlocks and joint ventures among major producers as well as among major and independent producers all frustrate the prospects for meaningful competition. These partnerships are initially formed in the bidding combinations for offshore leases, not only for an existing grouping, but with different partners splitting off and joining another combination of firms which results in an intricate web of working relationships. These joint ventures are then used to coalesce all the working interests on a lease by assigning an operator to market the gas for all the owners. Lastly, there are extensive individual interlocking relationships on the board of directors as well as bank interlocking relationships which undermines the prospects for competition in this market.

The hallmark of a workably competitive market is rivalry and independence among buyers and sellers. In the natural gas producer market buyers are also sellers and sellers are also buyers (because the majority of major producers have intrastate pipelines) and these anticompetitive arrangements undermines meaningful arm's length bargaining. In addition, the joint ventures and interlocks provides a commonality of interests which does not permit for workable competition.

The studies done in the Office of Economics of the FPC over the past 5-6 years have delineated the imperfections in the natural gas producer market. These institutional characteristics which lead to the inescapable conclusion that the producer market is not workably competitive are well documented because of the following factors:

a. concentration over "new" gas supplies;

b. interlocking relationships (joint ventures) among major producers and between major producers and smaller independent companies;

c. interlocking relationships (joint ventures) between producers and purchasing pipelines;

d. the existence of major bidding combines in recent offshore lease sales;

e. individual and bank director interlocks between major petroleum companies;

f. the dual role of the major producers as intrastate purchasers of gas for their pipeline systems and sellers of gas in the interstate market; and

g. the backward vertical integration of private distributors into production.

One can only conclude that in light of the extensive evidence on the monopolistic market structure of the natural gas producer market there is little hope for reasonable prices and adequate supplies by relying exclusively upon "market forces."

Evidence of Supply Constraint

The other side of the coin, of a market that is not reasonably competitive, is the evidence of supply constraint and the failure of supply response to significant price increases. In the past five years the FPC has increased prices approximately 30% per year. New additions to the interstate market (as well as total new additions) declined as prices increased. This supposedly negative price elasticity runs counter to the expectancies in a competitive market, but is a rational pattern in a monopolistic market in which price expectancies because of potential deregulation provide the prospects for significant increases in profit anticipations in the near future.

While I will not reiterate the extensive evidence of supply constraint which was documented by the Office of Economics at the FPC as far back as 1970, nonetheless, I refer you to my testimony of November 11, 1975, before this Committee. In that testimony I reviewed the evidence of major disparities between AGA reserve reporting and the FPC staff on offshore leases, the offshore investigation of producible but shut-in leases, the recent investigation of dedicated but nonproducing leases offshore (8.5 trillion cubic feet of natural gas), and other evidence of supply constraint.

To add to this long list of documentation concerning unreliable reserve reporting by the producers is the evidence that was disclosed last week before the Subcommittee on Oversight and Investigations. This unpublished study prepared by the U. S. Geological Survey covered 153 gas fields in the offshore Federal domain off Louisiana which accounts for more than two-third's of the Outer Continental Shelf natural gas reserves. The USGS study indicated 37.4% greater reserves than the producers reported to the AGA for the year end 1973. The underreporting by producers for these fields totaled an amazing 8.7 trillion cubic feet.

It is important to realize that the underreporting of reserves by producers to the AGA has two beneficial features: (1) It will bias the new gas nationwide costing before the FPC upward, and (2) It understates available supplies and provides tremendous pressure for deregulation.

In addition, studies by the same Subcommittee indicated the failure of producers (Getty Oil Co., Tenneco Inc.) to maintain deliverability in the Bastian Bay field (Southern Louisiana), and to perform the necessary work to maintain deliverability because of the anticipation of higher prices as a result of the proposed deregulation of natural gas. Similar findings were made with respect to the Garden City field (Louisiana) where the Subcommittee cited evidence that the producers (Exxon Corp., and Quintana Petroleum Corp.) were unwilling to undertake the drilling and other work projects necessary to maintain deliverability from the field and gave higher priority to the prospects designed to increase intrastate deliveries.

The failure by the producers to develop the offshore Federal domain is particularly ironical. One would expect that these public lands, even beyond the expectations of the development of private property, would be developed and produced to overcome our current shortage. The facts indicate otherwise. A comparison of producing leases in 1973 indicates that 71.2% of the offshore acreage in the Federal domain in the Gulf of Mexico was in a producing status but by 1974 the percentage dropped to 43.4%.

In fact, when the FPC terminated the advance payments program on December 31, 1975, the Commission noted that 90% of the funds advanced was for offshore production in the Texas Gulf Coast and the Southern Louisiana areas, but that the program had not had "the significant substantial impact on the development of natural gas reserves that was expected." The Commission concluded that it could not find "based on this record that there was sufficient quantifiable acceleration or initiation of exploration, development and production of offshore reserves to meet the test laid down by the Court of Appeals ...."

Proposed Legislation

There are a number of provisions which are similar between and among H. R. 9159, H. R. 11265, and S. 2310 on which there is general agreement. These relate to the collection of reserve information by the FPC, and the studies of production, gathering, storage, transportation, distribution, and the sale of natural, artificial, or synthetic gas. In addition, there are provisions prohibiting future boiler fuel use of natural gas, and phasing-out the existing use of natural gas for boiler fuel when alternative energy supplies are available and where feasible utilization of alternative fuels is possible. Lastly, the three bills require that the FPC in their curtailment priorities assure the availability of sufficient quantities of natural gas for essential agricultural purposes.

While the focus of my review of the proposed legislation will concern the major provisions, nonetheless, it is important to indicate that the Pearson-Bentsen and Krueger bills do not permit for a complete and comprehensive study of reserves, because the bills explicitly provide that the reserves held by small producers in individual fields and reservoirs shall not be included in the FPC study. This exclusion will seriously hamper a comparison with AGA reserve reporting, and provides the basis for incomplete data and may result in continued controversy in the future.

The Krueger bill and S. 2310 are similar with respect to the following provisions:

1. They deregulate the price of onshore new natural gas as of April 5, 1976. "New" natural gas is defined as gas committed to the interstate market for the first time after January 1, 1975, or produced from wells initiated or completed as an extension of previously discovered reservoir after that date.
2. They continue regulation of offshore natural gas for 5 years and authorize the FPC to set ceiling prices during the 1975-80 phase-out period.
3. The national ceiling price to be established by the FPC is to be predicated on new criteria in which the Commission is to consider (a) prospective cost of exploration, development, and production of natural gas, and (b) the rates are to be set so as to encourage the optimum levels of exploration, development, production, and gathering of natural gas, and (c) to maintain the proved reserves of natural gas.
4. The bills provide for the Commission to authorize rates in excess of the national ceiling for new natural gas produced from the offshore Federal domain for high cost production areas or by drilling depth.
5. The bills provide for an interim ceiling rate in advance of the national ceiling to be set by the Commission based upon the Btu equivalent rate of new domestic crude oil until a offshore rate is determined.
6. Lastly, the bills extend FPC jurisdiction to synthetic gas.

The Krueger bill and S. 2310 differ in the following respects:

1. In the application of the "new" gas coverage the Senate bill provides that gas dedicated under limited term certificates for 5 years or less or under temporary emergency controls shall be exempt from further regulation.
2. While these above provisions are not in the Kreuger bill, the following provision which is in H. R. 11265 but not in the Senate bill applies the "new natural gas" definition to gas flowing in interstate commerce under contracts that have expired under their own terms.
3. The Senate bill unlike the Kreuger bill requires separate rate schedules for "new" gas and "old" gas and for the assignment of old gas volumes and costs to the residential and small users to the extent possible.

Evaluation of the Kreuger and Pearson-Bentsen Bills

To assess the proposed legislation requires a dual focus as to the basic implications for public policy, as well as, a review of the explicit provisions within the framework of the bills themselves. Certainly questions can be raised with respect to the internal logic of the exemption from regulation for those supplies which were previously under contracts that have expired. Undoubtedly, in the majority of instances, the producers have received the return of their investment over the life of the contract, and deregulating the remaining volumes of gas is nothing more than providing the producers with pure economic rent.

Of a more basic nature the definition of "new natural gas" which permits reservoirs currently committed to interstate commerce to be exempt from regulation because the reservoir is produced for the first time (it may have been dedicated to interstate commerce many years in the past but purposely not developed) or produced from wells initiated and completed as an extension would in effect reward producers for failing to develop and produce reserves because of inventory speculation. This is indeed ironical in that these sales will reward producers for nonproduction or delivery of reserves in many instances on public lands, which previously was dedicated to interstate commerce.

Of a more fundamental nature, the Kreuger and Pearson-Bentsen bills will fulfill all the aspirations of the producers for higher prices and speculative profits precipitated by the supply constraint in the past 5-6 years. These bills are the wrong remedies for our supply problems and expectation of reasonable prices in light of the evidence on market structure and the noncompetitive dominance by the majors in the natural gas producer market.

In contrast to the assumption that deregulation may result in higher prices but it will significantly increase supplies,(which is a reasonable assumption in a workably competitive market), what we can anticipate is continued supply constraint by the majors in the natural gas market which parallels the high prices and supply constraints in crude oil and petroleum products. Put simply, the Congress should not capitulate to the pressures exerted by the major petroleum companies for deregulation that will result in billions of dollars of added consumer costs, but without any assurance of significant new supplies. The most predictable pricing and supply responses given the prevelance of monopoly power in this market is the continued constraints over supply to maintain and enhance prices and profits.

An Evaluation of H. R. 9159

The Fraser bill provides the only positive and meaningful framework for dealing with the question of market power and supply inadequacy. It is the only alternative before the Congress for establishing effective regulation which will protect the general public from exploitation and excessive prices. In addition, there is a start in dealing with the anticompetitive market characteristics of the joint ventures. While it prohibits joint ventures among the major integrated petroleum companies in the acquisition of natural gas or oil leases in the Federal domain, I would suggest a total prohibition of joint ventures of the majors with the smaller independent producers as a procompetitive option.

The strong positive features of the bill provide for the regulation of the entire market which will preclude the supply and price exacerbation associated with regulating just part of the natural gas market. Past experience indicates that the natural gas producers were able to leverage the prices in the intrastate market and use these monopolistic price levels to force higher prices for limited-term and emergency sales at the FPC above the just and reasonable rates determined on cost-based criteria. It is just as important to protect the intrastate users of gas from unreasonable prices in a monopoly market as it is to protect the interstate consumers. The "parity" prices between the intrastate and interstate market should close off the avenues existing in the past permitting producers to obtain unreasonable prices.

The Fraser bill realistically deals with the problem of non-production and development of Federal lands. It does so by requiring a careful monitoring program and a "produce or forfeit" requirement relative to offshore leases. A conscientious Commission and Secretary of Interior could eliminate the past abuses perpetuated by the majors in the failure to explore, develop, and produce in a timely manner the resources provided by the public for private gain. In other words, there are the prospects of eliminating speculative expectations by setting standards for developing Federal lands.

There are two areas in the Fraser bill that require additional evaluation as to the potential for determining just and reasonable rates. This relates to criteria for establishing an initial national base price, and for the need for a separate high-cost production base price for separate areas. In the former regard, the bill provides that the Commission shall consider current and prospective real costs and

an inflationary allowance is provided for other costs. I would recommend that the provision be changed to provide that current costs, but not prospective costs, be used as a basis for the initial national base price. I am concerned that the concept of "prospective costs" permits for speculation as to the inclusion in cost estimates elements which can be avoided by reliance on current costs. In addition, it may be advisable to either revert to area cost-based regulation rather than permitting for a nationwide rate and separate high-cost production base prices for other producing areas. It would appear that the logic for a nationwide rate is to average the current costs for all producing areas, or that we should return to individual area ratemaking.

Lastly, I would suggest that the provision concerning small producer pricing which provides for a rate of up to 50% of the authorized tional or other high-cost production base prices should be reexamined. The cost data submitted to the FPC does not justify a differential of 50% for small producers. In fact, it would appear that the costs associated with the production from leases held by small producers are less than the integrated major petroleum companies. I would suggest that area rates or a nationwide rate be established for all producers, and that special relief be provided in those instances where the individual producer cannot cover his costs or earn a fair return.

Conclusion

The meaningful alternatives are currently before the Congress. The Pearson-Bentsen bill and the Kreuger bill which postulate deregulation or the Fraser bill which extends and improves regulation are clear cut choices. As I indicated at the outset, the decision should be made on the basis of market structure. The extensive evidence of imperfections in the producer market, the noncompetitive arrangements among producers and among producers and pipelines, the overwhelming documentation of supply constraint indicate that deregulation would result in excessive prices, monopoly exploitation by producers, and no assurance of adequate supply. In my view, the Fraser bill best comports with the public interest and fashions public policy to meaningfully reform regulation and overcome supply blockages.

Hearing Before The

Subcommittee on Energy & Power

Committee on Interstate and Foreign Commerce

U.S. House of Representatives

Washington, D.C.

January 30, 1976

Testimony of
Dr. John W. Wilson

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I would like to thank the chairman and members of this committee for inviting me to testify before you this afternoon. This,as you all know,is a most serious occasion and one which I view with extreme concern because it appears to me that the United States Congress is on the verge of making an economic mistake that will cost consumers of this country approximately 20 billion dollars a year. The mistake to which I refer is, of course, the deregulation of the field price of natural gas.

If, as now seems possible, deregulation does take place, the legislators who make that decision will have to assume the responsibility. Regrettably, however, professional economists must share in the blame.

Not long ago the economics profession was generally able to express righteous indignation over our nation's economic debacles which were created in large measure without professional guidance. But that comparatively innocent era has past. Probably more so now than ever before our economic policy is at least in part a product of economic analysis, and obviously the result is not overly complimentary.

In the wake of a number of recent so-called studies by academic economists which advocate "market clearing prices" for natural gas, it is not surprising to find a good deal of rhetoric about free market forces resolving our natural gas problems. What seems to be missing in such appeals is an adequate realization that "free markets" and "competitive markets" are not necessarily synonymous concepts. Particularily in the natural gas industry where short-run supply and demand are price inelastic, a non-competitive free market is likely to produce grossly suboptimal results. That is, because supply and demand respond slowly and even then in small amounts to even major increases in the price of natural gas, the market clearing price in a monopolized market will result in massive income transfers from natural gas consumers to the petroleum industry and this situation will last for many years.

That is one of three points that I want to emphasize this afternoon--that market clearing prices are no solution to our problem in a monopolized market. Indeed, the fact that a market is monopolized is the only reason for regulating prices in the first place. In conjunction with this point, my second objective is to demonstrate to you that the natural gas producing industry is, indeed, a structural monopoly. It is not a competitive free market. Third, I am going to take a few moments to review with you the dismal history of attempts at antitrust enforcement in the petroleum industry. If antitrust enforcement were sufficient, and the industry was forced into a competitive posture, then of course price regulation would not be necessary. Some of those who would advocate deregulation would suggest to you that if competition is not effective then we should rely on our antitrust authorities and antitrust statues rather than regulation as the solution to the problem. In view of what has happened historically and in recent years, I would suggest to you that the antitrust prescription is a pipe dream--it's unrealistic. It is the solution which I would favor but it does not seem to be in the realm of political reality. In any event, it seems undeniably clear that we had better first have a functional antitrust policy before we scrap price regulation in monopolized industries.

Natural Gas: A Noncompetitive Industry

First, let us recognize that the natural gas producing industr is simply an integral part of the petroleum producing industry. The same firms which produce and control the bulk of this nations crude oil supply also produce and control natural gas. The only difference is that their control of natural gas is slightly greater and somewhat more integrated than their control of oil.

The key structural feature of the natural gas industry is that virtually all of its corporate entities are extensively tied together through a very large number of joint venture arrangements and other types of inter-corporate interlocks. Consequently, these firms can not be viewed as independent, unrelated market rivals as is generally the case for individual corporations in other industries.

It is a basic economic principle that whether or not an industry is competitive depends upon whether there is an adequate number of truly independent and self-motivated sellers in the marketplace. Without independence, self-interests bind interdependent sellers together in the mutual pursuit of common objectives which may not conform to the broader public interest.

Most natural gas production, and even oil production, is now done through extensive joint venture partnership arrangements between individual petroleum companies to the extent that most firms in the industry actually own the majority of their wells jointly with their so-called market rivals. In addition, crude oil and refined product transportation is carried out by joint venture pipeline enterprises and refining and marketing operations are generally dependent upon crude oil and product exchange agreements which further bind the individual market participants together in a common interest.

In addition to the fact that most natural gas production is now done through extensive joint venture partnership arrangements, it is also true that most exploratory drilling and a large majority of developmental drilling for oil and gas is undertaken jointly rather than competitively. Even lease acquisition (especially in federal off-shore areas) is generally undertaken as a joint endeavo Consequently, virtually all aspects of natural gas production involves substantial joint venture partnership arrangements among the various corporate entities which constitute the industry and both major vertically integrated companies and smaller independent producers have joined together with each other in the development and production of our petroleum resources. Every significant petroleum producer is involved in these joint pursuits. The industry's largest integrated firms, such as Exxon, Texaco, Mobil, Gulf, Amoco and Arco, share joint partnership interest's with each other and with other big and small producers alike. Established partnership patterns tend to carry over from exploration to development to production and the patterns are much the same in oil as they are in gas.

After the gas is produced by joint venture combines, it is sold to natural gas pipeline companies which transport it to markets throughout the country. It is this sale of natural gas by producers to the pipelines which Congress is asked to deregulate. The problem which I have been focusing on is that sales to pipelines do not take place in the competitive market environment because of the fact that the producers are partners, not competitors. But there is a further and equally serious problem. Frequently natural gas pipelines are owned in whole or in part by the major petroleum companies which produce natural gas. Even those pipelines which are not owned by the majors are owned by firms which themselves are engaged in natural gas exploration and production ventures--usually through joint venture partnership arrangements with major producers.

The natural gas pipelines and their affiliates have been major participants in federal offshore oil and gas lease sales, and in recent years they have been very active in acquiring onshore gas producing interests--nearly all of this through partnerships with major petroleum producers. The obvious consequence of this situation is that the pipelines which are the buyers of natural gas at the wellhead themselves have a vested interest in getting prices up--not holding them down. Functioning as regulated monopolies the pipelines are able to pass through to the gas distribution companies and ultimately to residential and commercial consumers the increased costs of purchased natural gas. Thus, in an unregulated market, they face strong incentives (because of their producing interests) to cooperate in efforts to raise prices. This is not a competitive market. Not only are the various sellers partners but the buyers are partners as well.

For example, since 1970 Texas Eastern, a major East Coast natural gas pipeline, has acquired interests in over 40 major offshore leases along with Standard Oil of Indiana, Union Oil, Marathon, Signal Oil, Ammarada Hess, and the Louisiana Land and Exploration Company. Similarly, United Gas Pipeline, the largest system in the Southeast, has acquired interests in 50 or more leases with companies such as Exxon, Texaco, Mobil, Ashland, Mesa, Getty, Cities Service Occidental, and other producers. In all, the major interstate pipelines have obtained working interests in about 50 percent of federally leased offshore oil and gas properties in recent years. Obviously, in circumstances such as these, consumers can hardly trust that they will be protected by unregulated free market bargains that are arranged between the producers and the pipelines.

In addition to their domestic joint ventures with each other, the major firms in the natural gas and petroleum industry have extensive joint foreign operations. They own the great bulk of this nation's natural gas processing plants jointly (plants which manufacture propane and butane and other gas liquids). They are signifigantly dependent upon each other for crude oil, gasoline, and other product exchanges, and there are a significant number of indirect (and some direct) interlocks between the boards of directors of major oil and gas companies.

It is not necessarily the case that any single one of the thousands of interlocks or joint venture arrangements which permeate so much of the petroleum industry in itself undermines workable competition between the partners. Nor would it be correct to conclude merely from their existance that joint venture interties are necessarily collusive arrangements consciously aimed at restraining competitive conduct. But whether they are intended to do that or not, that is obviously their result. It is the totality of all of these individual partnerships which produces the petroleum industry's unique form of structural integration. Regardless of the specific motives which may justify any individual joint venture or combination, because of the extensive and widespread nature of mutual intercorporate interests, it can not be presumed that the ultimate market results will in any way resemble what would happen in an industry where the proprietary and commercial interests of each firm are independent and competitively opposed to the self-interests of the other market participants. Whether or not one believes that certain combinations constitute collusive restraints of trade, when the entire mosaic is viewed in context, the extent to which these interlocks dominate the industry's structure is undeniable.

I have appended a series of tables documenting the extent of these joint ventures that I am talking about to my testimony. The fundamental problem that Congress should be aware of as it contemplates natural gas deregulation is that market forces simply can not be relied upon to curb price and supply abuses. Market control in the natural gas industry is held by a closely knit consortium comprised of large, fully integrated oil companies and their jointly interlocked affiliates. These firms, working in co-operation with each other, have the ability to control natural gas supplies and, in so doing, to maneuver the market toward monopolistic market clearing price levels.

Federal regulation of the field price of natural gas was supposedly designed to deal with this problem. It is apparent to everyone that in recent years natural gas price regulation has not worked well. A major reason for this is that in recent years many of our federal regulators have been working harder to deregulate than to regulate natural gas markets. No one can deny that some fundamental changes are needed. The prescription offered by the petroleum industry and its various spokesmen is for unrestrained "market freedom"--a situation wherein the industry (not the public) would be "free"--free, that is, to extract the maximum possible price that the market will bear. In this regard, the producers are fond of urging that petroleum prices should reflect "commodity value" rather than their production costs. Commodity value, however, is really nothing than the monopoly price in a monopolized market. Indeed, the essence of monopoly is the ability to extract a price equal to full commodity value, regardless of how exorbitant the resulting profit might be.

Unless capitulation to monopoly power of private economic interests is viewed by Congress to be a viable national policy option, this prescription makes no sense. Certainly, from the consuming public's view, it is not an optimal policy.

History of Antitrust Enforcements

An assertion which I am sure you have all heard frequently is that we already have antitrust laws on the books. Presumably then, if there is really a serious problem, the Justice Department or the Federal Trade Commission will deal with it; no additional legislative mandate or special direction or economic regulation is necessary. History, however, belies that contention.

The last major petroleum industry antitrust case brought by the Justice Department occurred during the 1930's, and withered away after more than twenty years without any significant remedies. On that occasion (i.e., the American Petroleum Institute or "Mother Hubbard" case) the government charged 22 major integrated oil companies and 379 of their subsidiaries with monopolizing crude oil production, transportation and marketing. The monopoly and conspiracy charges against the majors included predatory and discriminatory conduct against independent operators, tying arrangements, exclusive dealing and a variety of other anticompetitive practices which were illegal under the Sherman and Clayton Antitrust Acts and the Elkins Act. In addition to injunctive relief against these oil industry practices, the Judtice Department's suit sought divestiture of the transportation and marketing operations of vertically integrated firms. That action was never taken. As World War II intervened, Attorney General Jackson worked out a consent decree with the advice of the oil advisory committee of the Council for National Defense. Nine of the eleven committee members were connected with either Standard Oil or Shell, both defendants in the case.

Following the Federal Trade Commission Staff Report on the international oil cartel published in the early 1950's, a Federal grand jury was empaneled in 1952 to investigate criminal antitrust charges against the multi-national oil companies. President Truman offered to dismiss the grand jury and substitute a civil case instead if the companies would voluntarily supply documents subpoenaed by the government. That offer was refused by Standard Oil's lawyer Arthur Dean on grounds that the information sought by antiturst authorities would help the communist cause. In 1953 Dean's law partner, John Foster Dulles, became Secretary of State, and the new administration dismissed the grand jury investigation citing "natural security reasons."

In 1957 when twenty-nine U.S. oil companies were accused of using the Suez crisis as an opportunity to raise gasoline prices, another Federal grand jury empaneled in Virginia returned antitrust price-fixing indictments. The case was then transferred to Tulsa, where Judge Royce A. Savage dismissed all charges against the companies despite the fact that executive diaries showed that telephone meetings had taken place and companies knew what price levels others were going to invoke prior to their public announcements. One year later Judge Savage resigned from the bench to become a vice president of Gulf Oil, one of the defendants in the case.

In 1962, the Antitrust Division undertook an investigation of the potential anticompetitive consequences of the Colonial Pipeline Joint venture involving Mobil, Texaco, Gulf, Standard of Indiana, Atlantic Richfield, Cities Service, Continental, Union Oil and Sohio. Today, twelve years later, the Justice Department says that investigation is still "active".

More recently, in 1972, the Antitrust Division prepared civil investigation demands to investigate potential antitrust problems pertaining to the Trans-Alaska Pipeline which will be largely controlled by Exxon, B.P., and Atlantic Richfield in proportion to their control over Alaskan oil reserves. Senate testimony alleges that this investigation was vetoed by Attorney General John Mitchell. He and Maurice Stans were then in the process of collecting over $3 million from oil interests for the Nixon reelection campaign, and when Attorney General Mitchell learned of the Division's proposed petroleum investigation he write to Antitrust Chief Richard McLaren that, "in view of what is going on, this is not the time."*/

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*/ See testimony of Mark Green in Hearings on Market Performance and competition in the Petroleum Industry Before the Special Subcommittee on Integrated Oil Operations of the Senate Comm. on Interior and Insular Affairs, 93rd Cong., 1st Sess., pt. 1, at 375 (1963).

Bad Economic Advice

The substantive result of this antitrust inaction could, of course, be rationalized if anticompetitive problems were absent in the petroleum industry. Recent studies by economists which advocate price deregulation are based on that assumption. I stress that these studies assume the market to be competitive, they do not determine analytically that it is. That is the way that a great deal of theoretical work in economics is done these days. One simply assumes that markets are competitive and then proceeds to evaluate what would happen if prices rise or fall. The end result, of course, is neat and tidy econometric models with very little practical relevance.

Let me give you some examples of how these assumptions sneak into the work. A recent analysis of natural gas price regulation by Paul MacAvoy, who is now on President Ford's Council of Economic Advisors, proceeds as follows: "...in view of the lack of empirical support for the "monopoly power" theory, we shall assume that regulating producers' market power is not a sensible regulatory goal." Similarly, in his work on this subject, Milton Russell, a Council of Economic Advisors staff member, states "...the most productive analysis of the industry would probably proceed, as this one does, on the assumption that generally competitive conditions hold." And, another academic advocate of price deregulation, Keith Brown states in his book that his deregulation proposals are "based on the supposition that workable competition exists in most markets at most times."

The result of all of these assumptions and suppositions has been a proliferation of a good deal of silly and factually vacuous work by academic economists. For example, according to a recent study by an MIT Professor, it was shown that according to Ed Erickson's natural gas econometric model, given deregulation of natural gas prices so as to allow for a 15 cent price hike in 1974 and 4 cents per year thereafter, "new discoveries increase by about tenfold between 1971 and 1980, production out of reserves more than doubles in that time period, and we have excess supplies of 18 trillion cubic feet by 1980." That, of course, is absurd. Prices have risen by more than double that amount and supplies are still not forthcoming. Instead we are told that prices must double again and the best way to achieve that end is to deregulate them.

Conclusions such as these by the econometric modelers who rely upon baseless suppositions are quite harmless in a purely academic parlance. And, after all, they do generate subsequent rebuttal articles in obscure professional journals. It is however, quite another matter when studies such as these are offered authoritatively and taken literally by policy markers such as yourselves who are groping for elusive solutions to serious and immediate economic problems.

The political and economic consequences of following the advice of those that would urge you to ignore the facts and deregulate natural gas next week will be severe. As I stated at the outset, the annual cost to consumers will approach 20 billion dollars a year. The natural gas producing industry does not have a competitive structure. Natural gas sales at the wellhead do not take place in competitive markets. History has shown that antitrust enforcement can not be relied upon in this industry, and consequently, the free market equilibrium which will result from deregulation, will be a monopoly equilibrium with consumers being grossly overcharged in relation to the cost that is incurred by producers.

Almost 60 years ago, in the winter of 1918, Senator Boies Penrose, the political boss of Pennyslvania who was generally renown for a wide range of excesses introduced a proposal to base depletion for oil and gas wells on "market value" instead of "costs". LaFollette, Borah, and Norris, who warned that this would permit income tax right-offs to oil producers ten times as great as actual cost depletion, were able to muster only four other votes from that Congress to oppose Penrose. Today the oil industry's representatives are again urging their congressional colleagues to opt for "market value" instead of "cost"--this time as the legitimate basis for pricing natural gas. One hopes that when this question is put to you next Tuesday you will be well aware of the fact that "market value" is a derivative of market structure and that a free market price in a monopolized market setting is no bargain for consumers.

Ownership Interests in Producing Natural Gas Wells

(1973)

TOTAL U.S.

RESPONDENT	(1) GROSS WELLS (Number)	(2) GROSS WELLS JOINTLY OWNED (Number)	(3) (2) ÷ (1) %
American Petrofina	343	293	85.4
APCO Oil	513	499	97.3
Ashland Oil	2175	567	26.1
Champlin Petroleum	832	260 1/	31.2 2/
Cities Service	3308	1345	40.2
Clark Oil	14	14	100.0
Clinton Oil	527	353	67.0
Crown Central	260	167	64.2
Diamond Shamrock	908	230	25.3
Exchange Oil & Gas	146	146	100.0
Exxon	4427	1850 1/	41.8 2/
Forest Oil	238	193	81.1
General American	556	495	89.0
General Crude	541	489	90.4
Gulf Oil	3207	2070	64.5
Hunt Oil	24	17	70.8
Lone Star	835	285	34.1
Louisiana Land*	101	100	99.0
Monsanto	826	766	92.7
National Coop	177	174	98.3
Occidental Petroleum	175	158	90.3
Panhandle Eastern	1326	641	48.3
Pennzoil Co.	1821	871	47.8
Phillips	2736	1356	49.6
Southwestern Ref.	11	11	100.0
Standard Oil (Calif.) (Western Operations)	223	128	57.4
Standard Oil (Ohio)	435	397	91.3
Sun Oil 3/	1377	642	46.6
Texaco	4952	3136	63.3
Texas Oil & Gas	745	558	74.9
Total Leonard	7	7	100.0
Shell Oil	1828	1147	62.7
Union Texas (Allied)	492	483	98.2

* PAD III only, Louisiana Land and Exploration did not report their providing natural gas well interests for PAD I.

See footnotes on following page

[illegible] Ownership Interests in Producing Oil Wells,

(1973)

TOTAL U.S.

RESPONDENT	(1) GROSS WELLS (Number)	(2) GROSS WELLS JOINTLY OWNED (Number)	(3) (2) ÷ (1) %
American Petrofina	6674	5888	88.2
APCO Oil	4612	4488	96.9
Ashland Oil	6471	4867	75.2
Champlin Petroleum	4087	3014 1/	73.7 2/
Cities Service	14715	10818	73.5
Clark Oil	92	92	100.0
Clinton Oil	3001	2140	71.3
Crown Central	1231	125	10.2
Diamond Shamrock	975	294	30.2
Exchange Oil and Gas	134	109	81.3
Exxon	26694	15544 1/	58.2
Forest Oil	2642	2503	94.7
General American	6793	5878	86.5
General Crude	3012	2304	76.5
Gulf Oil	31196	21517	69.0
Hunt Oil	168	29	17.3
Lone Star	2277	2123	93.2
Louisiana Land	458	429	93.7
Monsanto	2443	2239	91.6
National Coop	2637	2513	95.3
Occidental Petroleum	359	294	81.9
Panhandle Eastern	1830	1565	85.5
Pennzoil Company	7963	2300	28.9
Phillips	17127	14705	85.8
Shell Oil	24795	16179	65.2
Southwestern Refining	22	22	100.0
Standard Oil (Calif.) (Western Operations)	10007	2958	29.6
Standard Oil (Ohio)	6664	6292	94.4
Sun Oil 3/	6809	3039	44.6
Texaco	55522	42813	77.1
Texas City Refining	91	52	57.1
Texas Oil & Gas	182	128	70.3
Total Leonard	37	37	100.0
Union Texas (Allied)	5770	5722	99.2

1/ Gross number of wells operated by others in which respondent owns an interest. The number of jointly owned wells operated by respondent is not included in this figure.

2/ To the extent that respondent operates wells in which others own an ~~interest, this percentage is understated.~~

3/ Sun Oil Co. reported this data only for wells operated by Sun. Since wells operated by others in which Sun owns an interest are by definition jointly owned, the percentage of Sun's gross number of wells jointly owned with others is understated.

Gross Domestic Exploratory Wells Drilled by Petroleum Companies

(1971-1973)

COMPANY/YEAR	(1) GROSS EXPLORATORY WELLS (Number)	(2) GROSS EXPLORATORY WELLS DRILLED WITH OTHERS (Number)	(3) (2) ÷ (1) (%)
Allied Chemical			
1973	26	21	80.8
1972	50	44	88.0
1971	28	22	78.6
American Petrofina			
1973	44	41	93.2
1972	28	24	85.7
1971	24	20	83.3
Atlantic Richfield			
1973	44	34	77.3
1972	*	*	*
1971	*	*	*
Belco Petroleum			
1973	28	28	100.0
1972	59	59	100.0
1971	74	74	100.0
Champlin Petroleum			
1973	8	8	100.0
1972	22	12	54.5
1971	54	26	48.1
Cities Service			
1973	76	56	73.7
1972	54	36	66.7
1971	42	33	78.6
Clark Oil			
1973	20	20	100.0
1972	17	17	100.0
1971	17	17	100.0
Clinton Oil			
1973	20	2	10.0
1972	29	3	10.3
1971	24	4	16.7
Crown Central			
1973	10	8	80.0
1972	12	0	0
1971	7	1	14.3

Sheet 2 of 4

COMPANY/YEAR	(1) GROSS EXPLORATORY WELLS (Number)	(2) GROSS EXPLORATORY WELLS DRILLED WITH OTHERS (Number)	(3) (2) ÷ (1) (%)
Diamond Shamrock			
1973	30	19	63.3
1972	24	19	79.2
1971	13	5	38.5
Exchange Oil & Gas			
1973	30	20	66.7
1972	30	24	80.0
1971	39	19	48.7
Forest Oil			
1973	26	24	92.3
1972	18	16	88.9
1971	32	22	68.8
Gen. American Oil (Texas)			
1973	16	8	50.0
1972	*	*	*
1971	*	*	*
Gen. Crude Oil			
1973	23	8	34.8
1972	23	9	39.1
1971	34	32	94.1
Hunt Oil			
1973	7	1	14.3
1972	3	0	0
1971	8	3	37.5
Kerr-McGee Corp.			
1973	30	26	86.7
1972	26	20	76.9
1971	24	16	66.7
Lone Star Prod. Co.			
1973	109	82	75.2
1972	63	41	65.1
1971	27	10	37.0
La. Land & Exploration			
1973	30	20	66.7
1972	16	7	43.8
1971	29	25	86.2

Sheet 3 of 4

COMPANY/YEAR	(1) GROSS EXPLORATORY WELLS (Number)	(2) GROSS EXPLORATORY WELLS DRILLED WITH OTHERS (Number)	(3) (2) ÷ (1) (%)
Monsanto Co.			
1973	33	29	87.9
1972	34	28	82.4
1971	25	19	76.0
Murphy Oil			
1973	6	2	33.3
1972	5	0	0
1971	5	4	80.0
Occidental Petroleum			
1973	40	40	100.0
1972	31	30	96.8
1971	70	56	80.0
Pennzoil Co.			
1973	58	50	86.2
1972	50	42	84.0
1971	58	44	75.9
Phillips Petroleum			
1973	67	44	65.7
1972	66	42	63.6
1971	42	33	78.6
Shell Oil Co.			
1973	170	70	41.2
1972	86	33	38.4
1971	*	*	*
Standard Oil (Ind.)			
1973	140	47	33.6
1972	133	44	33.1
1971	224	57	25.4
Standard Oil (Ohio)			
1973	18	18	100.0
1972	21	17	81.0
1971	28	28	100.0
Sun Oil			
1973	56	49	87.5
1972	120	62	51.7
1971	69	37	53.6

Sheet 4 of 4

COMPANY/YEAR	(1) GROSS EXPLORATORY WELLS (Number)	(2) GROSS EXPLORATORY WELLS DRILLED WITH OTHERS (Number)	(3) (2) ÷ (1) (%)
Tesoro Petroleum			
1973	55	42	76.4
1972	93	80	86.0
1971	61	58	95.1
Texas City Ref. Co.			
1973	7	5	71.4
1972	4	1	25.0
1971	5	0	
Total Leonard			
1973	23	23	100.0
1972	9	9	100.0
1971	0	0	--

* Not yet reported.

Gross Domestic Developmental Wells Drilled by Petroleum Companies

(1971-1973)

COMPANY/YEAR	(1) GROSS DEVELOPMENTAL WELLS DRILLED (Number)	(2) GROSS DEVELOPMENTAL WELLS DRILLED WITH OTHERS (Number)	(3) (2) ÷ (1) (%)
Allied Chemical			
1973	230	227	98.7
1972	91	81	89.0
1971	103	94	91.3
American Petrofina			
1973	58	51	87.9
1972	162	155	95.7
1971	112	105	93.8
Atlantic Richfield			
1973	712	615	86.4
1972	*	*	*
1971	*	*	*
Belco Petroleum			
1973	12	12	100.0
1972	56	56	100.0
1971	77	77	100.0
Champlin Petroleum			
1973	70	60	85.7
1972	63	45	71.4
1971	132	90	68.2
Cities Service			
1973	187	145	77.5
1972	178	132	74.2
1971	178	156	87.6
Clark Oil			
1973	22	22	100.0
1972	4	4	100.0
1971	3	3	100.0
Clinton Oil			
1973	19	10	52.6
1972	40	30	75.0
1971	43	14	32.6
Crown Central			
1973	25	22	88.0
1972	35	30	85.7
1971	*	*	*

Sheet 2 of 4

COMPANY/YEAR	(1) GROSS DEVELOPMENTAL WELLS DRILLED (Number)	(2) GROSS DEVELOPMENTAL WELLS DRILLED WITH OTHERS (Number)	(3) (2) ÷ (1) (%)
Diamond Shamrock			
1973	75	44	58.7
1972	48	23	47.9
1971	29	25	86.2
Exchange Oil & Gas			
1973	23	21	91.3
1972	18	18	100.0
1971	28	14	50.0
Forest Oil			
1973	17	15	88.2
1972	30	20	66.7
1971	58	36	62.1
Gen. American Oil (Texas)			
1973	26	13	50.0
1972	*	*	*
1971	*	*	*
Gen. Crude Oil			
1973	80	71	88.8
1972	107	83	77.6
1971	83	64	77.1
Hunt Oil			
1973	5	3	60.0
1972	6	2	33.3
1971	17	13	76.5
Kerr-McGee Corp.			
1973	33	25	75.8
1972	26	24	92.3
1971	35	33	94.3
Lone Star Prod. Co.			
1973	124	54	43.5
1972	63	39	61.9
1971	15	9	60.0
La. Land & Exploration			
1973	49	41	83.7
1972	47	32	68.1
1971	81	73	90.1

COMPANY/YEAR	(1) GROSS DEVELOPMENTAL WELLS DRILLED (Number)	(2) GROSS DEVELOPMENTAL WELLS DRILLED WITH OTHERS (Number)	(3) (2) ÷ (1 (%)
Monsanto Co.			
1973	50	46	92.0
1972	34	30	88.2
1971	20	15	75.0
Murphy Oil			
1973	10	10	100.0
1972	14	14	100.0
1971	3	1	33.3
Occidental Petroleum			
1973	13	12	92.3
1972	50	46	92.0
1971	40	34	85.0
Pennzoil Co.			
1973	168	113	67.3
1972	142	90	63.4
1971	119	39	32.8
Phillips Petroleum			
1973	524	447	85.3
1972	360	320	88.9
1971	276	247	89.5
Shell Oil Co.			
1973	555	350	63.1
1972	586	258	44.0
1971	*	*	*
Southwestern Refining			
1973	2	2	100.0
1972	0	0	--
1971	1	1	100.0
Standard Oil (Calif.)			
1973	149	59	39.6
1972	43	41	95.3
1971	25	23	92.0
Standard Oil (Ind.)			
1973	1024	638	62.3
1972	831	326	39.2
1971	472	250	53.0

Sheet 4 of 4

COMPANY/YEAR	(1) GROSS DEVELOPMENTAL WELLS DRILLED (Number)	(2) GROSS DEVELOPMENTAL WELLS DRILLED WITH OTHERS (Number)	(3) (2) ÷ (1) (%)
Standard Oil (Ohio)			
1973	99	88	88.9
1972	102	92	90.2
1971	110	92	83.6
Sun Oil			
1973	693	574	82.8
1972	366	289	79.0
1971	467	277	59.3
Tesoro Petroleum			
1973	47	36	76.6
1972	84	36	42.8
1971	55	51	92.7

* Not Reported

OWNERSHIP, CAPACITY AND THROUGHPUT OF CRUDE OIL PIPE LINES OVER 50,000 BARRELS PER DAY CAPACITY (1973 DATA)

PIPE LINE/OWNERS	OWNERSHIP PERCENTAGE	PERCENTAGE TOTAL THROUGHPUT BY AN OWNER
American Petrofina [1/] Pipe Line Co.		
American Petrofina	100%	100%
Ashland Pipeline Co. [2/]		
Ashland Oil	100%	100%
Basin Pipeline System [3/]		
Section I		
Atlantic Richfield	13.76%	*
Cities Service	9.18%	8.80% [4/]
Shell	34.86%	*
Texaco	42.20%	*
Section II		
Atlantic Richfield	12.45%	*
Cities Service	8.30%	*
Shell	34.02%	*
Texaco	45.23%	*
Butte Pipe Line Co. [5/]		
Burlington Northern	10%	*
Murphy	20%	*
Shell	51%	*
Western Crude Oil Inc.	19%	*

*Indicates not reported.

[1/] Capacity of 88,000 barrels per day; Annual throughput of 19,094,000 barrels.

[2/] Capacity of 378,000 barrels per day; Annual throughput of 139,841,000 barrels.

[3/] Capacity unreported; Annual throughput for entire two section pipe line of 173,785,000 barrels.

[4/] Represents percentage total throughput of Cities Service on entire Basin Pipeline System.

[5/] Capacity of 120,000 barrels per day; Annual throughput of 37,005,000 barrels.

Sheet 2 of 7

PIPE LINE/OWNERS	OWNERSHIP PERCENTAGE	PERCENTAGE TOTAL THROUGHPUT BY AN OWNER
Capline Pipeline 6/		
Ashland	22.94%	*
Marathon	15.28%	*
Mid-Valley P/L 7/	7.65%	*
Shell	11.15%	*
Southcap P/L 7/	21.60%	*
Standard Oil (Ind.)	7.44%	*
Texaco	13.94%	*
Capwood Pipeline 8/		
Clark Oil	33.83%	33.16%
Shell	66.17%	59.39%
Chicap Pipe Line Co. 9/		
Clark Oil	22.76%	18.34%
Standard Oil (Ind.)	29.17%	16.44%
Union Oil	48.07%	27.76%
Cook Inlet Pipe Line Co. 10/		
Atlantic Richfield	*	*
Marathon Oil	30%	35.76%
Mobil Oil	*	*
Union Oil of Calif.	*	*
CRA Inc. 11/		
CRA Inc.	100%	100%

*Indicates not reported.

6/ Capacity of 624,000 barrels per day; Annual throughput unreported.

7/ The Southcap pipe line is owned 50% by Clark Oil Co. and 50% by Union Oil Co. of California; the Mid-Valley pipe line is, as listed herein, co-owned by Sun Oil, Standard Oil (Ohio) and Gulf.

8/ Capacity of 133,000 barrels per day; Annual throughput of 35,024,000 barrels.

9/ Capacity of 270,000 barrels per day; Annual throughput of 106,684,000 barrels.

10/ Capacity ranging from 72,000 to 200,000 barrels per day; Estimated annual throughput of 47,815,000 barrels.

11/ Capacity of 85,000 barrels per day; Annual throughput of 19,388,000 barrels.

PIPE LINE/OWNER	OWNERSHIP PERCENTAGE	PERCENTAGE TOTAL THROUGHPUT BY AN OWNER
Crescent Pipeline Co. 12/		
Tenneco	100%	*
East Texas Main Line 13/		
Cities Service	45.65%	43.62%
Crown Central Petr.	20.00%	*
Texaco	34.35%	*
Enid Refr. Crude Pipeline System 14/		
Champlin Petr.	100%	100%
FIN-COS Corp. 15/ (Cosden Pipe Line System)		
American Petrofina	100%	100%
Four Corners Pipe Line Co. 16/		
Atlantic Richfield	10%	*
Continental	10%	*
Gulf	20%	*
Shell	25%	*
Standard Oil (Calif.)	25%	*
Superior Oil	10%	44.50%

*Indicates not reported.

12/ Capacity of 67,000 barrels per day; Line acquired by Tenneco mid-1973.

13/ Capacity unreported; Annual throughput of 21,819,000 barrels.

14/ Capacity of 69,000 barrels per day; Annual throughput of 18,160,000 barrels.

15/ Capacity of 65,000 barrels per day; Annual throughput unreported.

16/ Capacity of 80,000 barrels per day; Annual throughput of 10,895,000 barrels.

PIPE LINE/OWNERS	OWNERSHIP PERCENTAGE	PERCENTAGE TOTAL THROUGHPUT BY AN OWNER
Jayhawk Pipeline Corp. 17/		
NCRA	50%	*
Coastal States Gas Prod. Co.	50%	*
Kaw Pipe Line Co. 18/		
Cities Service	33.33%	26.72%
Phillips Petr.	33.33%	13.36%
Texaco	33.33%	1.66%
Kenai Pipeline Co. 19/		
Atlantic Richfield	50%	33.60%
Standard Oil (Calif)	50%	31.52%
Kerr-McGee Crude System 20/		
Kerr-McGee Corp.	100%	100%
Mesa Pipe Line System 21/		
Cities Service	15.33%	17.96%
Gulf	64.35%	66.60%
Standard Oil (Ohio)	5.07%	4.44%
Sun Oil	6.50%	5.09%
Union Oil	8.76%	5.88%
Mid-Continent Pipe Line Co. 22/		
Claymont Investment Co. (Sun)	100%	100%
Minnesota Pipeline Co. 23/		
Ashland Oil	33.30%	37.08%
J. How. Marshall	7.10%	*
Koch Ref'g.	59.60%	*

*Indicates not reported.

17/ Capacity of 280,000 barrels per day; Annual throughput unreported.

18/ Capacity unreported, Annual throughput of 17,201,000 barrels.

19/ Capacity of 160,000 barrels per day; Annual throughput of 22,812,000 barrels.

20/ Capacity of 70,000 barrels per day; Annual throughput of 24,591,000 barrels.

21/ Capacity of 316,000 barrels per day; Annual throughput of 103,762,000 barrels.

22/ Capacity of 146,000 barrels per day; Annual throughput of 52,122,000 barrels.

23/ Capacity of 170,000 barrels per day; Annual throughput of 57,150,000 barrels.

PIPE LINE/OWNERS	OWNERSHIP PERCENTAGE	PERCENTAGE TOTAL THROUGHPUT BY AN OWNER
Owensboro-Ashland 24/ Pipeline		
Ashland Oil	100%	100%
Phillips Pipe Line Co. 25/		
Ranch System		
Segment I		
Ashland Oil	4.97%	*
Atlantic Richfield	20.49%	*
Charter Oil	8.05%	*
Crown Central Petr.	4.37%	2.68%
Phillips Petr.	7.03%	*
Shell	35.25%	*
Segment II		
Ashland Oil	*	*
Atlantic Richfield	*	*
Charter Oil	*	*
Crown Central Petr.	*	*
Phillips Petr.	*	*
Shell	*	*
Standard Oil (Ind.)	*	11%
Segment III		
Ashland Oil	4.97%	*
Atlantic Richfield	20.49%	*
Charter Oil	8.05%	*
Crown Central Petr.	4.97%	*
Phillips Petr.	7.03%	*
Shell	35.25%	*
Standard Oil (Ind.)	2.80%	*

*Indicates not reported.

24/ Capacity of 179,000 barrels per day; Annual throughput of 1,317,000 barrels.

25/ Capacity of 311,000 barrels per day in Section I, 385,000 barrels per day in Section II, and 322,000 barrels per day in Section III; Annual throughput for entire system of 224,528,000 barrels.

Sheet 6 of 7

PIPE LINE/OWNERS	OWNERSHIP PERCENTAGE	PERCENTAGE TOTAL THROUGHPUT BY AN OWNER
Platte Pipe Line Co.[26]		
Atlantic Richfield	25%	7.78%
Continental	20%	11.84%
Gulf	15%	0.54%
Marathon Oil	25%	28.74%
Union Oil	15%	4.68%
Southcap Pipe Line Co.[27]		
Clark Oil	50%	33.49%
Union Oil	50%	54.27%
Tecumseh Pipeline Co.[28]		
Ashland Oil	20%	12.62%
Atlantic Richfield	40%	*
Union Oil	40%	*
Texaco-Cities Pipe Line Co.[29][30]		
Cities Service	50%	8.36%
Texaco	50%	44.39%

*Indicates not reported

26/ Capacity of 155,000 barrels per day; Annual throughput of 65,533,000 barrels.

27/ Capacity unreported; Annual throughput of 44,704,000 barrels.

28/ Capacity of 120,000 barrels per day; Annual throughput of 55,422,000 barrels.

29/ Crude and product line.

30/ Capacity unreported; Annual throughput of 88,726,000 barrels

Sheet 7 of 7

PIPE LINE/OWNERS	OWNERSHIP PERCENTAGE	PERCENTAGE TOTAL THROUGHPUT BY AN OWNER
Texas-New Mexico 31/ Pipe Line Co.		
Atlantic Richfield	35%	*
Cities Service	10%	10.96%
Getty Oil	10%	*
Texaco	45%	41.52%
West Texas Gulf 32/ Pipe Line		
Cities Service	11.40%	20.58%
Gulf	57.72%	50.08%
Standard Oil (Ohio)	9.23%	4.34%
Sun Oil	12.61%	14.30%
Union Oil	9.04%	6.30%
Whitecap Pipeline 33/		
Paloma Pipeline	33.33%	29.23%
Union Oil	53.33%	46.18%
Whiteshoal 34/	13.33%	16.95%
Woodpat Pipeline 35/		
Marathon Oil	40%	54.96%
Texaco	60%	45.09%

*Indicates not reported.

31/ Capacity unreported; Annual throughput of 173,284,000 barrels of which 34.26% was by non-owners.

32/ Capacity unreported; Annual throughput of 154,587,000 barrels.

33/ Capacity of 173,000 barrels per day; Annual throughput of $37,959,000 barrels.

34/ Whiteshoal Pipeline Corp. Ownership:

Kerr-McGee Corp.	64.5%
Cabot Corp.	16.1%
Felmont Corp.	9.7%
Case-Pomeroy Oil	9.7%

35/ Capacity of 311,000 barrels per day; Annual throughput of 53,883,000 barrels.

OWNERSHIP, CAPACITY AND THROUGHPUT OF PRODUCT OIL PIPE LINES OVER 20,000 BARRELS PER DAY CAPACITY (1973 DATA)

PIPE LINE/OWNERS	OWNERSHIP PERCENTAGE	PERCENTAGE TOTAL THROUGHPUT BY AN OWNER
Amdel Pipe Line Co.[1]		
American Petrofina [2]	50%	59.62%
Union Oil	50%	40.28%
ATA System [3]		
Diamond Shamrock Oil and Gas	33.33%	39.33%
Phillips Petr.	33.33%	29.62%
Texaco	33.33%	31.04%
Badger Pipeline Co. [4]		
Atlantic Richfield	34%	*
Cities Service	32%	58.02%
Texaco	22%	21.29%
Union Oil	12%	*
Casa Products System [5]		
Atlantic Richfield	50%	*
Gulf	50%	*
Cherokee Pipe Line Co.[6]		
Continental	100%	44.44%
Choctaw to Geismar System[7] (Ethylene)		
Allied Chemical	41.7%	*
BASF Wyandotte	41.6%	*
Marbon	16.7%	*
Collins Pipe Line Co.[8]		
Murphy Oil Co.	20%	*
Tenneco Oil Co.	80%	*

* Indicates not reported.

[1] Capacity of 25,000 barrels per day; Annual throughput of 1,127,000 barrels.

[2] Also owns 30% of Amdel crude line with Standard Oil (Ohio) owning the other 70%.

[3] Capacity of 21,000 barrels per day; Annual throughput of 6,420,000 barrels.

[4] Capacity of 163,000 barrels per day; Annual throughput of 51,363,000 barrels.

[5] Capacity of 144,000 barrels per day; Annual throughput unreported.

[6] Annual throughput of 63,000,000 barrels; Capacity unreported.

[7] Capacity of 25,000 barrels per day; Annual throughput unreported.

[8] Capacity of 163,000 barrels per day; Annual throughput unreported.

PIPE LINE/OWNERS	OWNERSHIP PERCENTAGE	PERCENTAGE TOTAL THROUGHPUT BY AN OWNER
Colonial Pipe Line Co.[9]		
Atlantic Richfield	1.58%	*
B.P. Oil	8.96%	1.14%
Cities Service	13.98%	0.25%
Continental	7.55%	*
Gulf	16.78%	15.70%
Mobil Oil	11.49%	*
Phillips Petr.	7.10%	4.13%
Standard Oil (Ind.)	14.32%	9.58%
Texaco	14.27%	13.66%
Union Oil	3.97%	*
Dixie Pipeline Co. (LPG)[10]		
Allied Chemical	8.59%	9.76%
Atlantic Richfield	7.38%	*
Cities Service	5.00%	5.04%
Continental	4.05%	5.43%
Exxon	11.05%	22.28%
Gulf	18.22%	3.14%
Mobil Oil	5.00%	*
Phillips Petr.	14.53%	5.86%
Shell Oil	5.53%	*
Standard Oil (Ind.)	12.08%	9.66%
Texaco	5.00%	5.43%
Transcontinental	3.57%	*
Enid Refinery Products System[11]		
Champlin Petr.	100%	100%
Everglades Pipeline Co.[12]		
Buckeye	41%	*
Cities Service	39%	17.24%
Phillips Petr.	10%	*
Union Oil	10%	*

* Indicates not reported.

9/ Capacity of 1,464,000 barrels per day; Annual throughput of 519,432,000 barrels with 23.82% total Colonial throughput by non-owners.

10/ Capacity of 300,000 barrels per day; Annual throughput of 25,714,000 barrels with 6.89% total Dixie throughput by non-owners.

11/ Capacity of 36,000 barrels per day; Annual throughput of 10,839,000 barrels.

12/ Annual throughput of 13,643,000 barrels; capacity unreported.

PIPE LINE/OWNERS	OWNERSHIP PERCENTAGE	PERCENTAGE TOTAL THROUGHPUT BY AN OWNER
Explorer Pipeline Co. [13/]		
APCO Oil	2.92%	*
Cities Service	6.80%	11%
Continental	7.70%	6.60%
Gulf	26.69%	*
Phillips Petr.	4.52%	2.37%
Shell Oil	26.00%	*
Sun Oil	9.40%	7.98%
Texaco	15.97%	18.70%
Harbor Pipe Line System [14/]		
Gulf Oil	33.33%	38.43%
Standard Oil (Ohio)	33.33%	22.82%
Texas Pipe Line	33.33%	38.74%
Houston Gathering System [15/]		
Gulf	100%	100%
Inland Corp. [16/]		
Shell Oil	27%	*
Standard Oil (Ohio)	47%	66.80%
Sun Oil	10%	7.07%
Union Oil	16%	*
Lake Charles Pipe Line Co. [17/]		
Cities Service	50%	71.31%
Continental	50%	28.68%
Lake Charles to Geismar Pipe Line (Ethane) [18/]		
Allied Chemical	100%	*

*Indicates not reported.

13/ Capacity reported as ranging from 304,000 barrels per day gasoline and 272,000 barrels per day oil, - 360,000 per day Port Arthur to Tulsa, and 216,000 barrels per day Tulsa-Hammond; Annual throughput reported as ranging from 85,045,000 - 79,117,000 barrels

14/ Capacity of 144,000 barrels per day; Annual throughput of 37,741,000 barrels.

15/ Capacity of 250,000 barrels per day; Annual throughput of 31,128,000 barrels.

16/ Capacity of 300,000 barrels per day; Annual throughput of 102,813,000 barrels. Voting percentages are Shell 25%, Standard Oil 50%, Sun 10% and Union Oil 15%.

17/ Annual throughout of 84,214,000 barrels; capacity unreported.

18/ Capacity of 30,000 barrels per day; Annual througout unreported.

Sheet 4 of 7

PIPE LINE/OWNERS	OWNERSHIP PERCENTAGE	PERCENTAGE TOTAL THROUGHPUT BY AN OWNER
Laurel Pipe Line Co. 19/		
Gulf	49.11%	39.10%
Standard Oil (Ohio)	17.01%	15.94%
Texaco	33.88	31.80%
Lindgulf Product System 20/		
Gulf	50%	*
Texaco	50%	*
Marathon Pipeline Co. 21/		
Marathon Oil	100%	73.46%
Miami Valley Corp. 22/		
Standard Oil (Ohio)	20%	*
Union Oil	80%	*
Michigan-Ohio Pipeline Corp. 23/		
Total Leonard	100%	100%
NCRA Products Line 24/		
Nat'l. Coop. Ref'g. Assoc.	100%	*
Ohio Product Pipe Line 25/		
Standard Oil (Ohio)	100%	100%
Olympic Pipe Line Co. 26/		
Mobil Oil	29.5%	*
Shell Oil	43.5%	*
Texaco	27%	*

*Indicates not reported.

19/ Capacity ranging from 148,000 to 200,000 barrels per day; Annual throughput of 44,078,000 barrels with 13.09% of total Laurel throughput by non-owners.

20/ Capacity and throughput not reported.

21/ Annual throughput of 66,407,000 barrels

22/ Capacity of 40,000 barrels per day; annual throughput unreported. Voting control is shared equally by owners.

23/ Capacity of 49,000 barrels per day; Annual throughput of 12,800,000 barrels.

24/ Capacity of 49,000 barrels per day; Annual throughput of 5,383,000 barrels.

25/ Capacity of 75,000 barrels per day; Annual throughput of 23, 192,000 barrels

26/ Capacity ranging from 110,000 to 170,000 barrels per day; Annual throughput of 62,452,000 barrels with 37.93% of total Olympic throughput by non-owners.

PIPE LINE/OWNERS	OWNERSHIP PERCENTAGE	PERCENTAGE TOTAL THROUGHPUT BY AN OWNER
Plantation Pipe Line Co. 27/		
Exxon	48.83%	32.61%
Shell	24.04%	19.60%
Standard Oil (Calif.)	27.13%	17.80%
Port Arthur Products Station 28/		
Gulf	33.33%	*
Texas Pipe Line	33.33%	*
Union Oil	33.33%	*
SAAL System 29/		
Amarillo to Abernathy Section		
Diamond Shamrock Oil & Gas	33.33%	69.75%
Phillips Petr.	33.33%	19.32%
Texaco	33.33%	9.83%
McKee to Amarillo Section 30/		
Diamond Shamrock Oil & Gas	100%	*
Sarnia Pipeline System 31/		
Dome Pipe Line Corp.	50.0%	*
Standard Oil (Ind.)	50.0%	*

*Indicates not reported.

27/ Capacity of 506,000 barrels per day; Annual throughput of 184,668,000 barrels.

28/ Capacity of 792,000 barrels per day; Annual throughput unreported.

29/ Capacity of 21,000 barrels per day; Annual throughput of 11,668,000 barrels.

30/ Capacity of 22,000 barrels per day; Annual throughput unreported.

31/ Capacity of 55,000 barrels per day; Annual throughput unreported.

PIPE LINE/OWNERS	OWNERSHIP PERCENTAGE	PERCENTAGE TOTAL THROUGHPUT BY AN OWNER
Trans Texas System [32]		
Diamond Shamrock Oil & Gas	100%	100%
Valvoline Oil Co. [33]		
Ashland Oil	100%	100%
West Shore Pipe Line Co. [34]		
Cities Service	8%	3.22%
Clark Oil	8%	8.30%
Continental	6.5%	6.90%
Exxon	3.5%	1.22%
Marathon Oil	9%	9.97%
Mobil Oil	14%	*
Shell Oil	20%	*
Standard Oil (Ind.)	16.5%	15.60%
Texaco	9%	5.38%
Union Oil	5.5%	*
Wolverine Pipe Line Co. [35]		
Cities Service	8%	4.43%
Clark Oil	11%	*
Marathon Oil	10%	7.31%
Mobil Oil	21%	8.12%
Shell Oil	7%	9.26%
Texaco	17%	*
Union Oil	26%	*

*Indicates not reported.

[32] Capacity of 21,000 barrels per day; Annual throughput of 5,762,000 barrels.

[33] Capacity of 43,000 barrels per day; Annual throughput of 6,990,000 barrels.

[34] Capacity of 170,000 barrels per day; Annual throughput of 59,769,000 barrels with 23.54% of total throughput by non-owners.

[35] Capacity of 270,000 barrels per day; Annual throughput reported as ranging from 99,547,000 to 92,044,000 barrels.

PIPE LINE/OWNERS	OWNERSHIP PERCENTAGE	PERCENTAGE TOTAL THROUGHPUT BY AN OWNER
WYCO Pipe Line Co. 36/		
Mobil	20%	*
Standard Oil (Ind.)	40%	31.35%
Texaco	40%	25.81%
Yellowstone Pipe Line Co. 37/		
Continental	40%	59.12%
Exxon	40%	39.75%
Husky Oil	6%	*
Union Oil	14%	*

36/ Capacity reported ranging from 11,000 barrels per day to 52,000 barrels per day; Annual throughput of 22,243,000 barrels with 29.45% of total throughput by non-owners.

37/ Capacity 50,000 barrels per day; Annual throughput 18,363,000 barrels

Domestic Natural Gas Processing Plants Owned by Atlantic Richfield Company Together with Major Producing Companies, as of January 1, 1974

Atlantic Richfield	Total Number of Plants	Percentage of Total Number of Plants	Total Capacity* (1000 mcf/day)	Percentage of Total Capacity
Wholly owned	15	19.0	595	5.5
Owned with others	64	81.0	10151	94.5
Total	79	100.0	10746	100.0
Co-owners				
Amerada Hess	11	13.9	2184	20.3
Cities Service	21	26.6	5898	54.9
Continental Oil	19	24.0	6708	62.4
Exxon	26	32.9	7396	68.8
Getty Oil	21	26.6	6857	63.8
Gulf Oil	22	27.8	4650	43.3
Marathon Oil	13	16.4	2027	18.9
Mobil Oil	21	26.6	4477	41.7
Pennzoil Co.	4	5.1	2130	19.8
Phillips Petr.	15	19.0	1531	14.2
Shell Oil	21	26.6	5610	52.2
Standard Oil (Calif.)	8	10.1	3498	32.6
Standard Oil (Ind.)	28	35.4	7126	66.3
Standard Oil (Ohio)	4	5.1	313	2.9
Sun Oil	30	38.0	4762	44.3
Superior Oil	6	7.6	2191	20.4
Tenneco	13	16.4	4236	39.4
Texaco	20	25.3	1844	17.2
Union Oil (Calif.)	21	26.6	4042	37.6
Others**	4	5.1	76	0.7

* The cumulative total capacity of all gas processing plants in which Atlantic Richfield owns an interest.

** Other petroleum companies or individuals with whom Atlantic Richfield shares ownership interests in gas processing plants in which none of the above petroleum companies also share ownership interests.

Sheet 2 of 9

Domestic Natural Gas Processing Plants Owned by Cities Service Oil Company Together with Major Producing Companies, as of January 1, 1974

Cities Service	Total Number of Plants	Percentage of Total Number of Plants	Total Capacity* (1000 mcf/day)	Percentage of Total Capacity
Wholly owned	30	42.8	2,335	23.8
Owned with others	40	57.1	7,450	76.2
Total	70	100.0	9,785	100.0
Co-owners				
Amerada Hess	7	10.0	875	8.9
Atlantic Richfield	25	35.7	6,337	64.8
Continental Oil	12	17.1	5,013	51.2
Exxon	16	22.8	5,460	55.8
Getty Oil	12	17.1	5,390	55.1
Gulf Oil	14	20.0	5,485	56.1
Marathon Oil	5	7.1	580	5.9
Mobil Oil	9	12.8	1,903	19.4
Pennzoil Co.	1	1.4	100	1.0
Phillips Petr.	8	11.4	1,205	12.3
Shell Oil	16	22.9	5,668	57.9
Standard Oil (Calif.)	4	5.7	3,370	34.4
Standard Oil (Ind.)	14	20.0	4,757	48.6
Standard Oil (Ohio)	3	4.3	455	4.6
Sun Oil	18	25.7	2,211	22.6
Superior Oil	5	7.1	2,168	22.2
Tenneco	10	14.3	3,849	39.3
Texaco	14	20.0	1,812	18.5
Union Oil (Calif.)	14	20.0	3,545	36.2
Others**	7	10.0	461	4.7

* The cumulative total capacity of all gas processing plants in which Cities Service owns an interest.

** Other petroleum companies or individuals with whom Cities Service shares ownership interests in gas processing plants in which none of the above petroleum companies also share ownership interests.

Domestic Natural Gas Processing Plants Owned by Continental Oil Company Together with Major Producing Companies, as of January 1, 1974

Continental Oil	Total Number of Plants	Percentage of Total Number of Plants	Total Capacity* (1000 mcf/day)	Percentage of Total Capacity
Wholly owned	8	20.0	436	4.6
Owned with others	32	80.0	9,058	95.4
Total	40	100.0	9,494	100.0
Co-owners				
Amerada Hess	8	20.0	3,365	35.4
Atlantic Richfield	21	52.5	6,790	71.5
Cities Service	12	30.0	4,993	52.6
Exxon	11	27.5	6,848	72.1
Getty Oil	12	30.0	6,256	65.9
Gulf Oil	10	25.0	4,956	52.2
Marathon Oil	8	20.0	2,740	28.9
Mobil Oil	11	27.5	4,240	44.6
Pennzoil Co.	3	7.5	2,675	28.2
Phillips Petr.	10	25.0	2,464	26.0
Shell Oil	13	32.5	6,244	65.8
Standard Oil (Calif.)	4	10.0	4,400	46.3
Standard Oil (Ind.)	17	42.5	6,827	71.9
Standard Oil (Ohio)	2	5.0	175	1.8
Sun Oil	14	35.0	3,760	39.6
Superior Oil	5	12.5	1,619	17.0
Tenneco	10	25.0	3,925	41.3
Texaco	6	15.0	565	6.0
Union Oil (Calif.)	12	30.0	4,108	43.3
Others**	4	10.0	258	2.7

* The cumulative total capacity of all gas processing plants in which Continental Oil owns an interest.

** Other petroleum companies or individuals with whom Continental Oil shares ownership interests in gas processing plants in which none of the above petroleum companies also share ownership interests.

Domestic Natural Gas Processing Plants Owned by Mobil Oil Corporation Together with Major Producing Companies, as of January 1, 1974

Mobil Oil	Total Number of Plants	Percentage of Total Number of Plants	Total Capacity* (1000 mcf/day)	Percentage of Total Capacity
Wholly owned	16	25.8	1,609	14.7
Owned with others	46	74.2	9,328	85.3
Total	62	100.0	10,937	100.0
Co-owners				
Amerada Hess	5	8.1	2,225	20.3
Atlantic Richfield	20	32.2	4,406	40.3
Cities Service	8	12.9	1,665	15.2
Continental Oil	11	17.7	4,775	43.6
Exxon	15	24.2	5,146	47.0
Getty Oil	11	17.7	3,407	31.2
Gulf Oil	14	22.6	3,328	30.4
Marathon Oil	10	16.1	2,705	24.7
Pennzoil Co.	3	4.8	2,730	25.0
Phillips Petr.	11	17.7	2,850	26.0
Shell Oil	12	19.4	3,793	34.7
Standard Oil (Calif.)	6	9.7	2,247	20.5
Standard Oil (Ind.)	19	30.6	5,147	47.1
Standard Oil (Ohio)	2	3.2	100	0.9
Sun Oil	19	30.6	4,690	42.9
Superior Oil	8	12.9	1,793	16.4
Tenneco	12	19.4	2,173	19.9
Texaco	17	27.4	2,915	26.6
Union Oil (Calif.)	19	30.6	4,062	37.1
Others**	2	3.2	15	0.1

* The cumulative total capacity of all gas processing plants in which Mobil Oil owns an interest.

** Other petroleum companies or individuals with whom Mobil Oil shares ownership interests in gas processing plants in which none of the above petroleum companies also shareownership interests.

Domestic Natural Gas Processing Plants Owned by Phillips Petroleum Company Together with Major Producing Companies, as of January 1, 1974

Phillips Petroleum	Total Number of Plants	Percentage of Total Number of Plants	Total Capacity* (1000 mcf/day)	Percentage of Total Capacity
Wholly Owned	10	28.6	1,280	22.7
Owned with Others	25	71.4	4,359	77.3
Total	35	100.0	5,639	100.0
Co-owners				
Amerada Hess	4	11.4	330	5.8
Atlantic Richfield	13	37.1	1,172	20.8
Cities Service	3	8.6	360	6.4
Continental Oil	7	20.0	1,712	30.4
Exxon	7	20.0	1,564	27.7
Getty Oil	4	11.4	198	3.5
Gulf Oil	8	22.8	2,162	38.3
Marathon Oil	5	14.3	324	5.7
Mobil Oil	10	28.6	2,177	38.6
Pennzoil Co.	2	5.7	1,370	24.3
Shell Oil	7	20.0	1,945	34.5
Standard Oil (Calif.)	5	14.3	1,680	29.8
Standard Oil (Ind.)	12	34.3	2,328	41.3
Standard Oil (Ohio)	1	2.8	63	1.1
Sun Oil	11	31.4	2,343	41.5
Superior Oil	3	8.6	1,455	25.8
Tenneco	2	5.7	78	1.4
Texaco	3	8.6	333	5.9
Union Oil (Calif.)	7	20.0	2,205	39.1
Others**	4	11.4	1,238	22.0

* The cumulative total capacity of all gas processing plants in which Phillips Petroleum owns an interest.

** Other petroleum companies or individuals with whom Phillips Petroleum shares ownership interests in gas processing plants in which none of the above petroleum companies also share ownership interests.

Sheet 6 of 9

Domestic Natural Gas Processing Plants Owned by Standard Oil Company of California Together with Major Producing Companies, as of January 1, 1974

Standard Oil Company of California	Total Number of Plants	Percentage of Total Number of Plants	Total Capacity* (1000 mcf/day)	Percentage of Total Capacity
Wholly owned	11	34.4	512	8.0
Owned with others	21	76.6	5,884	92.0
Total	32	100.0	6,396	100.0
Co-owners				
Amerada Hess	3	9.4	2,000	31.3
Atlantic Richfield	8	25.0	3,563	55.7
Cities Service	4	12.5	3,420	53.5
Continental Oil	6	18.8	4,485	70.1
Exxon	8	25.0	5,215	81.5
Getty Oil	7	21.9	3,492	54.6
Gulf Oil	8	25.0	3,493	54.6
Marathon Oil	5	15.6	2,152	33.6
Mobil Oil	6	18.8	2,350	36.7
Pennzoil Co.	2	6.2	1,350	21.1
Phillips Petr.	5	15.6	1,630	25.5
Shell Oil	9	28.1	5,380	84.1
Standard Oil (Ind.)	9	28.1	5,315	83.1
Standard Oil (Ohio)	1	3.1	12	-
Sun Oil	6	18.8	1,618	25.3
Superior Oil	4	12.5	3,210	50.2
Tenneco	2	6.2	1,873	29.3
Texaco	6	18.8	1,014	15.8
Union Oil (Calif.)	7	21.9	3,530	55.2
Others**	2	6.2	23	-

* The cumulative total capacity of all gas processing plants in which Standard Oil (Calif.) owns an interest.

** Other petroleum companies or individuals with whom Standard Oil (Calif.) shares ownership interests in gas processing plants in which none of the above petroleum companies also share ownership interests.

Sheet 7 of 9

Domestic Natural Gas Processing Plants Owned by Standard Oil Company of Ohio Together with Major Producing Companies, as of January 1, 1974

Standard Oil Company of Ohio	Total Number of Plants	Percentage of Total Number of Plants	Total Capacity* (1000 mcf/day)	Percentage of Total Capacity
Wholly Owned	4	22.2	93	12.2
Owned with Others	14	77.8	667	87.8
Total	18	100.0	760	100.0
Co-owners				
Amerada Hess	2	11.1	135	17.8
Atlantic Richfield	6	33.3	500	65.8
Cities Service	3	16.7	325	42.8
Continental Oil	2	11.1	175	23.0
Exxon	5	27.8	422	55.5
Getty Oil	4	22.2	277	36.4
Gulf Oil	7	38.9	437	57.5
Marathon Oil	1	5.6	12	1.6
Mobil Oil	3	16.7	115	15.1
Pennzoil Co.	1	5.6	20	2.6
Phillips Petr.	2	11.1	175	23.0
Shell Oil	4	22.2	247	32.5
Standard Oil (Calif.)	2	11.1	32	4.2
Standard Oil (Ind.)	4	22.2	350	46.0
Sun Oil	7	38.9	400	52.6
Superior Oil	0	0	0	0
Tenneco	3	16.7	140	18.4
Texaco	3	16.7	265	34.9
Union Oil (Calif.)	2	11.1	225	29.6
Others**	2	11.1	20	2.6

* The cumulative total capacity of all gas processing plants in which Standard Oil (Ohio) owns an interest.

** Other petroleum companies or individuals with whom Standard Oil (Ohio) shares ownership interests in gas processing plants in which none of the above petroleum companies also share ownership interests.

Sheet 8 of 9

Domestic Natural Gas Processing Plants Owned by Tenneco, Inc. Together with Major Producing Companies, as of January 1, 1974

	Total Number of Plants	Percentage of Total Number of Plants	Total Capacity* (1000 mcf/day)	Percentage of Total Capacity
Tenneco				
Wholly Owned	2	6.7	175	2.8
Owned with Others	28	193.3	6,129	97.2
Total	30	100.0	6,304	100.0
Co-owners				
Amerada Hess	4	13.3	385	6.1
Atlantic Richfield	12	40.0	3,707	58.8
Cities Service	9	30.0	3,610	57.3
Continental Oil	8	26.7	3,525	55.9
Exxon	11	36.7	4,557	72.3
Getty Oil	11	36.7	3,808	60.4
Gulf Oil	13	43.3	4,968	78.8
Marathon Oil	5	16.7	245	3.9
Mobil Oil	8	26.7	1,455	23.1
Pennzoil Co.	1	3.3	1,200	19.0
Phillips Petr.	4	13.3	465	7.4
Shell Oil	14	46.7	5,073	80.5
Standard Oil (Calif.)	2	6.7	1,873	29.7
Standard Oil (Ind.)	13	43.3	3,937	62.4
Standard Oil (Ohio)	0	0	0	0
Sun Oil	13	43.3	1,058	16.8
Superior Oil	5	16.7	3,320	52.7
Texaco	6	20.0	1,662	26.4
Union Oil (Calif.)	6	20.0	2,376	37.7
Others**	0	0	0	0

* The cumulative total capacity of all gas processing plants in which Tenneco owns an interest.

** Other petroleum companies or individuals with whom Tenneco shares ownership interests in gas processing plants in which none of the above petroleum companies also share ownership interests.

Sheet 9 of 9

Domestic Natural Gas Processing Plants Owned by Texaco, Inc. Together with Major Producing Companies, as of January 1, 1974

	Total Number of Plants	Percentage of Total Number of Plants	Total Capacity* (1000 mcf/day)	Percentage of Total Capacity
Texaco				
Wholly Owned	32	37.2	4,190	37.7
Owned with Others	54	62.8	6,924	62.3
Total	86	100.0	11,114	100.0
Co-owners				
Amerada Hess	5	5.8	1,096	9.9
Atlantic Richfield	19	22.1	1,816	16.3
Cities Service	11	12.8	1,010	9.1
Continental Oil	5	5.8	473	4.2
Exxon	19	22.1	3,085	27.8
Getty Oil	16	18.6	1,948	17.5
Gulf Oil	22	25.6	2,857	25.7
Marathon Oil	6	7.0	1,165	10.5
Mobil Oil	17	19.8	3,173	28.5
Pennzoil Co.	2	2.3	1,106	10.0
Phillips Petr.	6	7.0	590	5.3
Shell Oil	15	17.4	2,890	26.0
Standard Oil (Calif.)	7	8.1	1,050	9.4
Standard Oil (Ind.)	15	17.4	3,255	29.3
Standard Oil (Ohio)	3	3.5	205	1.8
Sun Oil	20	23.2	2,223	20.0
Superior Oil	6	7.0	647	5.8
Tenneco	4	4.6	1,090	9.8
Union Oil (Calif.)	14	16.3	1,760	15.8
Others**	2	2.3	90	0.8

* The cumulative total capacity of all gas processing plants in which Texaco owns an interest.

** Other petroleum companies or individuals with whom Texaco shares ownership interests in gas processing plants in which none of the above petroleum companies also share ownership interests.

STATEMENT BEFORE THE
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
U. S. HOUSE OF REPRESENTATIVES

JANUARY 30, 1976

COMPETITION IN THE FIELD MARKETS FOR NEW NATURAL GAS SUPPLIES

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SUMMARY

We have examined structural, behavioral and performance aspects of the U.S. petroleum industry with special reference to field markets for natural gas.

We conclude that in the context in which public policy for natural gas field markets is being set, that the appropriate market definition is a national one. This definition means that concentration ratios for gas supplies are consistent with a competitive industry. Economists often quarrel with regard to the spatial, temporal and product market definitions which underlie concentration ratios. Concentration ratios are also only a partial measure of the effective competition in an industry. We therefore also examine behavioral and performance aspects of the industry.

The performance analysis involved comparing the return on stockholders' equity for the eight major petroleum companies to:
- --the average for Moody's 125 industrials,
- --the average for all manufacturing industry,
- --the average for Moody's 24 utilities, and
- --the cost of equity capital for these companies.

The conclusion from these comparisons is that the petroleum industry is effectively competitive.

An analysis was also performed on bidding behavior for offshore tracts in the Gulf of Mexico. Many of the bids were made by joint bidding ventures. A discounted cash flow investment model was used.to predict bonus bids per acre. Observed bids slightly exceeded predicted bids for the 1972 and 1973 lease sales. This evidence, plus an analysis of bidding partnerships and the record of entry into offshore activity, strongly indicates that the industry is effectively competitive. This evidence is in direct conflict with others' allegations to the contrary based on less sophisticated analysis.

The problems of consequences for consumers of deregulation of natural gas field market prices and the creation of a national energy company are also briefly discussed. The conclusions are that a national energy company, even on the scale of TVA, would only make a marginal long-run contribution to the natural gas supply problem and would make no immediate contribution. In addition the consumer consequences of natural gas field market price deregulation would be higher prices, but these prices would allow relatively smooth consumer adjustments, would limit necessary abandonments and curtailments, and would call forth substantial new gas supplies.

Our major conclusions are that natural gas field markets are effectively competitive and that the most efficacious solution to the natural gas dimensions of the energy crisis is deregulation of the wellhead price of natural gas.

1. There is a shortage of natural gas reserves and production.

2. This shortage is a result of a variety of factors. Some of these factors include:
    - -- shortages of refinery capacity and crude oil inputs,
    - -- shifts of fuel demands to natural gas,
    - -- Federal Power Commission ceilings on the wellhead price of natural gas, and
    - -- uncertainties about the future of regulation of the wellhead price of natural gas.

3. Regulatory reform is a necessary ingredient for a long-run solution of our natural gas shortage.

4. The question of competition in the field markets for natural gas was an important issue in the early, formative years of regulation.

5. Competition in the field markets for natural gas is now a critical issue in the discussion of regulatory reform.

6. The question of competition is an emotional one. This emotion often shows through in statements about the presence or absence of competition. (See for example the statements of Dr. John Wilson before various Senate commitees and Appendix A of this statement.)

7. Because of the emotion involved, it is desirable to use empirical analysis to generate light as well as heat.

8. Empirical analysis involves more than simply counting up numbers. Empirical analysis involves framing questions as testable hypotheses. The numbers are then used to test the hypotheses. Whether the test results are positive or negative determines whether a hypothesis is accepted or rejected.

9. Analysis of the degree of competition centers on three areas:
    - -- structure,
    - -- behavior, and
    - -- performance.

10. Analysis of the degree of competition must also include definitions of:
    - -- the product,
    - -- the industry,
    - -- the geographic market, and
    - -- the temporal market.

11. The definitions of product, industry and markets are critical to an analysis of structure. By misdefinition of the relevant market in one direction or the other, such structural indices as concentration ratios may be made arbitrarily high or low. There has been more heat than light shed by analysis of concentration ratios for various dimensions of natural gas field markets.

12. New supplies of natural gas should be the focal point of concern.

13. In the absence of regulatory reform which rejuvenates the domestic search for conventional sources of new natural gas reserves, the long-run solution to the natural gas shortage will more rapidly include imported LNG and domestic SNG. If the solution to the natural gas shortage includes imported LNG from the Soviet Union and SNG from Illinois and western coal in, say, 1980, then the relevant concentration ratios for new supplies of conventional natural gas should not be limited to uncommitted reserves (shelf inventories) in the current year in a narrowly defined area.

14. This broader definition of the geographic and temporal market for new supplies has one important drawback. New supplies of conventional sources of natural gas are, by and large, undiscovered supplies. It is impossible to compute a concentration ratio on something that does not yet exist in marketable form. Fortunately, a proxy exists. This proxy is the concentration ratio for current production. Current production reflects the cumulative record of past additions to reserves through discoveries and development. On the basis of concentration ratios for current production, and relative to the rest of the American economy, field markets for natural gas are not very highly concentrated.

15. The problem of drawing conclusions from concentration ratios is compounded by the fact that there is no widely accepted, unique level of concentration which unambiguously separates "monopoly" from "competition".

16. The Congress and the Courts are familiar with the ambiguities of concentration ratios and the rhetoric on one side or the other for particular industries in particular proceedings. Because of this, it is desireable to examine the behavior and performance of industries.

17. In the context of natural gas field markets, the most frequently discussed aspects of behavior include:
    --inter-firm relations in joint bidding combinations for offshore acreage, and
    --affiliated relations between interstate pipeline companies and their producer subsidiaries.

18. Performance in natural gas field markets is difficult to separate from the overall performance of the whole petroleum industry. A relevant dimension of performance involves the relation between price and long-run marginal costs. Rates of return on investment provide an index for this relation. Some data exist for offshore operations. Other data exist for the overall industry (production, transportation, refining and processing, marketing

and distribution). Thus it is possible to look at two indices of performance:
- --overall long-run profitability for the whole petroleum industry, and
- --the rate of return to offshore activity.

19. Empirical analysis of behavioral and performance dimensions of natural gas field markets indicate that these markets are effectively competitive.

20. Offshore production of natural gas now accounts for almost 20 percent of total production. Offshore areas are even more important in terms of prospective new supplies. Thus, offshore activity is an important test case for competitive behavior.

21. It has been alleged that the prevalence of joint bidding ventures in offshore exploration is evidence of collusion. "... [T]here is little or no substantive difference between the end result obtained from the formation of a bidding combine and the end result of a conspiratorial agreement to rotate bids."

22. There are at least two possible explanations for joint bidding ventures:
    - --collusion, and
    - --risk pooling.

    These explanations are not perfectly mutually exclusive, but the patterns of partnership in joint bidding can reveal which is dominant.

23. If joint bidding ventures are collusive, one would expect to see the following pattern:
    - --stable bidding partnership relations (to minimize the transaction costs of collusion),
    - --similar firms bidding together (because collusion, not risk pooling, is the dominant motive), and
    - --potential entrants to offshore activity excluded from joint bidding ventures with the larger firms (to preserve the field for the members of the colluding set).

24. If joint bidding ventures are principally a method for pooling risks, one would expect to see the following pattern:
    - --the incidence of joint bidding increase as firm size decreases (i.e., defense against gamblers' ruin),
    - --a heavy incidence of joint bidding partnerships between unlike firms (to take advantage of dissimilar risk preferences), and
    - --smaller firms using joint bidding ventures as a vehicle for entry into offshore activity (because the field is open and attractive).

25. The observed patterns of bidding partnerships is most consistent with the hypothesis that joint bidding is a means of risk sharing. The patterns are:
    - --there is turnover from year to year in the membership of bidding groups and market shares are unstable,
    - --the most frequent bidding group is a combination of majors

and smaller firms, but majors bid alone and so do smaller firms,
- --single firm bids are frequently make by the largest firms, but other firms are also successful single firm bidders, and
- --bidding groups which contain a large number of firms are predominately composed of smaller firms.

For example, in 1973 there were four successful one-firm bids by non-majors. In the two 1972 lease sales, there were thirty-two successful one-firm bids by non-majors and twenty-five successful one-firm bids by majors. With regard to the fourteen two-firm bidding groups in 1973, ten had zero majors, one had four majors and none had two majors. With regard to the forty-two two-firm bidding groups in 1972, fourteen had zero majors, thirty-two had one major and six had two majors. In 1973, there were two seven-firm bidding groups with no majors and one eight-firm bidding group with no majors. In 1972, there were two nine-firm bidding groups composed of one major and eight non-majors. Also in 1972, there was one eight-firm bidding group composed of one major and seven non-majors. There were three seven-firm bidding groups in 1972. Two of these groups had no major and one had one major.

26. There would be no surer way to limit offshore exploration to a few of the largest firms than to require that all bids be made by single firms with no joint bidding permitted.

27. Interstate pipeline companies have affiliated producer subsidiaries. This is a cause for concern to many observers because they correctly presume that transactions between affiliated parent/subsidiary companies may not be completely at arms length. This concern should increase:
    - --as the fraction of sales between affiliated companies increases as a percent of total market sales, and
    - --as the requirements of any parent pipeline company are increasingly supplied by its subsidiary producing company.

28. The percentage of total market sales that is sales between affiliated interstate pipeline/producer subsidiary companies is now relatively low. The percentage of interstate pipelines' requirements that are met by their own producer subsidiaries is also now relatively low. But, in the absence of regulatory reform, these percentages can be expected to increase. Even in the presence of regulatory reform, these parent/subsidiary relations between interstate pipelines and their affiliated producing companies will continue to cloud the issue of competition in the field markets for natural gas. These relations could be severed by:
    - --direct legislation, or
    - --appropriate use of cost based regulation to create incentives for divestiture.

Severing the affiliated relationship between interstate pipelines and their producer subsidiaries could be accomplished in a way which would work no financial hardship on the pipeline companies. Moreover, such divestiture would not have any adverse effect on the social efficiency of natural gas field markets.

29. Bigness is often confused with monopoly. The petroleum industry is a large industry, and the firms within it are also large. Effective monopoly results in a divergence between long-run marginal costs and prices. Prices in excess of long-run marginal costs (including a competitive return on invested capital) result in excessive earnings. These excessive earnings are reflected in higher than normal, above average rates of return on stockholders' equity capital. Thus, the rate of return on corporate stockholders' equity capital is one measure of the presence or absence of market power in the petroleum industry.

30. The Federal Trade Commission has recently issued a complaint which charges the major oil companies with monopoly practices. In the FTC complaint, rates of return are discussed. Rate of return data is relevant to a discussion of whether or not the earnings of companies contain evidence of the exercise of monopoly power. In our judgment, a careful examination of the rates of return for the major oil companies does not indicate evidence of monopoly earnings. Instead, rate of return data indicate that the major oil companies earn a competitive rate of return. In addition, rate of return data indicate that the petroleum industry has been getting more competitive in recent years.

31. For the period 1961-1971, on average, four of the eight major petroleum companies earned a lower rate of return on stockholders' equity than the average for all manufacturing industry. Four of the eight major petroleum companies earned more than the average for all manufacturing. Thus, the rate of return experience for the eight major petroleum companies has not been atypical with respect to all manufacturing. As with any average, some earn above the average and some earn below the average.

32. For the period 1961-1971, on average, six of the eight major petroleum companies earned less on stockholders' equity than the average of Moody's 125 industrials. Two of the eight major petroleum companies earned more than the average for Moody's 125 industrials.

33. If the period is expanded to include the years 1951-1971, there is evidence that the profits of the eight major petroleum were higher (relative to all manufacturing industry and Moody's 125 Industrials) in the earlier years of 1951-1960 than they were in the later years of 1961-1971.

34. For the years 1951-1971, five of the eight major petroleum companies earned more on stockholders' equity than the average for all manufacturing industry. Two earned less.

35. For these same 1951-1971 years, five of the eight major petroleum companies earned less on stockholders' equity than the average for Moody's 125 industrials. Three earned more.

36. Relative to the averages for both all manufacturing and Moody's 125 industrials, the eight major petroleum companies were more profitable for the 1951-1971 period than for the 1961-1971 period. This could only occur if they were more profitable in the years 1951-1960 than in the years 1961-1971. Profitability has been decreasing. To the extent that decreased long-run profitability is an index of increased competition, the profitability indices

indicate that the petroleum industry has been becoming more rather than less competitive. (This indication is consistent with, for example, the record of entry into offshore activity.)

37. Long-run profitability is the appropriate measure of competitiveness. Petroleum firms have had dramatic increases in profits in recent quarters. Two points must be made with regard to these profit increases. First, a substantial portion of petroleum firms' profit increases are the result of regulatory failures. The chief contributing factors were: (1) failure to relax mandatory oil import quotas in an orderly and expeditious fashion; (2) the regulation induced shortage of natural gas production and reserves; and (3) the subsequent effect of environmental controls to shift fuel demands to natural gas and to prolong the shortages of refinery capacity and refined products. Second, these petroleum firm profit increases must be standardized for inflation and compared to the profit increases in other sectors of the economy. After such a standardization and comparison is made, petroleum firms' recent short-term profits are not extraordinary when viewed relative to the backdrop of the total economy. Rather, they are the signals that in a well functioning economy would cause resources to flow into this industry and ultimately return profits to their long-run levels.

38. Comparison to averages such as Moody's 125 industrials and all manufacturing industry may be misleading. This is because some of the non-petroleum firms in these averages may possess market power. This makes the averages themselves higher than the normal, long-run, competitive rate of return. There is a way to correct for this. A standard procedure in regulatory proceedings is to calculate the cost of equity capital for the particular firm(s) in question. Earnings on equity capital are then compared to the cost of equity capital.

39. Modern, sophisticated analysts typically calculate a range for the cost of equity capital. This is because a range is more reliable than a point estimate. Using standard techniques for the years 1967-1971, the range for the cost of equity capital for the eight major petroleum companies is 10.3 to 12.3 percent. The midpoint of this range is 11.3 percent.

40. For this same 1967-1971 period, the average earnings on stockholders' equity for the eight major petroleum companies were 11.5 percent. Within the limits of the precision of such calculations, the earnings on stockholders' equity (11.5 percent) and the cost of equity capital (11.3 percent) are approximately equal. This is what we would expect in an effectively competitive industry operating in an economy with well functioning capital markets. The rate of return data indicate that the eight major petroleum companies are part of a competitive industry and are themselves earning the competitive rate of return. If simple monopoly power or more complex collusive behavior were an important feature for the petroleum industry, one would expect it to show up in the rate of return data. It does not.

41. The rate of return data examined here do not indicate that the petroleum industry has been competitive in all times or in all places. It is well known that some of the classic American antitrust cases involve the petroleum industry. One of the costs of maintaining a competitive economy is constant surveillance

by the antitrust agencies. But the recent rate of return do indicate that this surveillance has paid off -- at least with respect to the petroleum industry.

42. There is another possible difficulty with regard to rate of return analysis when it is applied to large, integrated companies operating in several distinct markets. This possible difficulty is that the companies may have monopoly power in some markets, but not in others. In such a case, monopoly earnings in some markets may be used to subsidize less than competitive earnings in other markets. The effect could then be an overall rate of return on equity capital equal to the cost of equity capital with monopoly earnings in some markets submerged in the overall average. (Such a situation leaves unanswered the question of why a company not regulated on a rate base, fair rate of return standard would persist in operating in a market in which it was earning less than the competitive rate of return. We pose this question, but do not consider it further.) The market in question in these hearings is the field market for natural gas. An important component of the field market for natural gas is the offshore area in the Gulf of Mexico. Nearly 20 percent of our total natural gas production comes from this offshore area, and this area will be even more important in the future. Fortunately, a good deal of data exist which allows the application of rate of return analysis to the offshore area in the Gulf of Mexico.

43. In order to determine if the rates of return in the Gulf of Mexico offshore area are competitive and typical of the competitive rate of return earned by the petroleum industry, we analyzed the available data. This financial and economic analysis included lease bonuses, so it is also relevant to the question of "collusive joint bidding combines". There is one methodological difference between the offshore rate of return analysis and the eight major company average analysis reported above. First, the rates of return are computed on total assets. This is because it is impossible to break out the equity capital components on a disaggregated basis. This difference is adjusted for and does not affect the conclusions. Second, in addition to discussing retrospective rates of return, we analyzed prospective rates of return for the three most recent lease sales. This analysis involved computing competitive lease bids on the basis of a discounted cash flow model. These results are discussed below. The prospective analysis also required estimating future oil and gas prices. These price assumptions are also discussed below.

44. There have been a number of studies of the rate of return on investment expenditures for offshore exploration, development and production. These studies conclude that the rate of return for offshore activity is approximately equal to the competitive rate of return on investment in the American economy. We have carefully reviewed these studies (including sensitivity analysis) and have concluded that their findings are basically correct. These findings are consistent with the conclusions of staff studies for the Cabinet Task Force on Oil Import Control.

45. One of the recent studies was done by L.K. Weaver and associates of the Bureau of Mines. This was a very detailed engineering-economics study of a typical, successful 5,000 acre offshore tract in the Gulf of Mexico.

[Not all tracts are successful.]

The Weaver study indicated that the rate of return on total assets committed varied between 14 and 17 percent -- depending on the rate of withdrawal of the oil and gas. The Weaver study, however, was for a successful tract. For example, only 40 percent of the tracts leased in 1970 have resulted in commercially feasible production. Some of the currently unproductive tracts may yet become producers, but the effect of some unproductive acreage is to reduce the rate of return toward the competitive rate.

46. An estimate of prospective profitability is of more interest than a study of retrospective profitability. The data underlying the Weaver study is very complete and amenable to adjustment to reflect current economic conditions. We have adjusted the Weaver data on the basis of the current economic situation. Current investment decisions are based on forecasts of future prices and costs. Our adjustments included:

--increasing geophysical, platform and drilling costs to current rates, and
--assuming oil prices of $5 a barrel and gas prices of 65 cents per MCF.

We then used a rate of return on total assets of eight percent and Weaver's estimated reserve data to build a discounted cash flow model which takes into account the fact that in an overall offshore exploration campaign not all tracts are successful. This model was then used to predict bonus bids per acre for the 1972 and 1973 lease sales. The predicted bids were then compared to actual bids as an indicator of the competitiveness of both offshore production activity and the bidding process.

47. The test of competitiveness is the relation between predicted and observed bids. If predicted bids exceed observed bids, then this is an indication that the Federal Treasury is not capturing all the rents from offshore tracts. If observed bids are approximately equal to or exceed predicted bids, then this is an indication that a competitive bidding process is at work. This is a straightfoward test, but it must be applied to a number of lease sales. Just as is the case of a computation of the cost of equity capital, a range of data which includes some of the variation from lease sale to lease sale is more reliable. Also, this is a single test and its results must be considered jointly with other available evidence.

48. Our discounted cash flow model predicts bids per acre for the 1972 and 1973 lease sales as follows:

--12/19/72; $3,108 per acre,
-- 9/12/72; $2,017 per acre, and
-- 6/19/73; $2,908 per acre.

The average predicted bid for the three lease sales equaled roughly $2,500 per acre. The observed bid for the three lease sales equaled roughly $2,700 per acre. The observed average bid slightly exceeds the predicted average bid.

49. The bidding evidence suggests that the offshore leasing process is highly competitive and that rents resulting from the unit cost advantages of offshore areas are captured by society at large in the form of payments to

the Federal Treasury. This behavioral evidence is consistent with the structural evidence from concentration ratios and the performance evidence from the analysis of overall industry profitability

50. The evidence from the offshore bidding data is especially important for public policy formation with regard to natural gas field markets. It indicates that higher supply prices for new natural gas supplies are the result of the higher costs of securing those supplies. It is true that offshore areas are quite important in current production, and even more important in terms of prospective production. But offshore areas still account for a minority fraction of total production (relative to onshore areas) and will do so for the balance of this decade. It is also true that offshore areas have lower unit costs (net of bonus payments) than do onshore areas. In light of this, two questions may be asked, "What do offshore costs, including bonuses, have to do with onshore costs?; and, Why should we allow prices to rise on offshore gas if those price increases will simply be captured by the Federal Treasury as increased bonus payments?".

There are several points which should be made with regard to these questions.

--Offshore costs including bonuses are a reasonable proxy for onshore costs. If the companies could discover and produce onshore gas at lower costs than the costs (including bonuses) for offshore gas, and sell it in intrastate markets, they would do so. The basic economics of maximizing profits by equating at the margin indicates that the unit costs of incremental onshore new gas supplies must be in the neighborhood of those for offshore gas.

--Not all offshore tracts are successful and commercially feasible. Higher prices for offshore gas will make some tracts that are not now productive commercially feasible and will also stimulate more intensive drilling. The net effect of this will be to increase offshore areas' gas supplies that will be available to the interstate market. We need all the gas we can get.

--Artifically holding offshore gas prices down to a level below that of the best substitute--onshore gas--will encourage waste in consumption. Prices will lag further behind opportunity costs and aggravate the existing shortage. A significant part of the current shortage is demand induced. In addition to finding ways to stimulate supply, public policy should also cause available supplies to be rationed among the highest valued uses. The price system is the most efficient rationing system we know. A way to both stimulate new supply and conserve our scarce gas resources by allocating them to their highest valued use is to allow market clearing prices to operate.

51. Although markets in which prices are allowed to clear demands and supplies are the most efficient rationing systems for allocating scarce resources among competing uses, would not allowing the field markets for new natural gas to clear work an inequitable hardship on gas consumers? A rough calculation is illustrative here. Suppose that the price which would clear field-markets for natural gas is three times the current average level of prices. Further

assume that the reserves production ratio is 10:1 and that the prices for natural gas supplies now committed to the interstate market are protected by contracts. Then allowing field market prices to clear would only result in about a 20 percent increase in rolled-in consumer prices. This would amount to a nickel or so per MCF at the burner tip. (This calculation is a rough approximation. A more detailed calculation would have to include adjustments for contract terms, exhaustion rates and market growth.) Consumer prices would further increase as new gas replaced old gas in the pipeline mix. But these increases would be gradual and would allow consumers to adjust smoothly. Moreover, these prices would perform the rationing function discussed above that is so important to the effective conservation of natural gas resources. We believe that consumers would prefer to have adequate gas supplies at prices which reflected the costs of the resource they are using rather than curtailments and abandonments at artificially low prices. In addition, to the extent that it might be desirable to favor residential (and other) users, it would be possible to require that direct sales to industrial users be made at prices reflecting the marginal costs of incremental new gas supplies.

52. It has been suggested that one part of the solution to the natural gas portion of the energy crisis should be the formation of a national energy company to explore for, develop and produce new natural gas reserves. There is one example of such a venture in another area. This is TVA. The total assets of TVA are about $4,000,000,000. The total assets of Amerada-Hess are $1,378,000,000. Thus, if we were to create a national energy company dedicated to oil and gas production, it would only be about 3 times as large as Amerada-Hess. Even if all the resources of such a venture were committed to oil and gas exploration and production, the contribution of such a venture to the long-run oil and gas supply problem would be marginal. Moreover, we could not create such a national energy company overnight. The natural gas supply problem is here and now. The most promising solution to the natural gas crisis is to allow prices in the field markets for new natural gas supplies to rise to their market clearing level.

53. There has been considerable discussion of the accuracy of reserve statistics with regard to the public policy discussion surrounding field markets for natural gas. Available reserve data have been used on all sides of the debate. Reserve estimation is at best an imprecise science. There is no way to be completely accurate about remaining recoverable reserves until a field is abandoned. We are not surprised at the differences in estimates that have been cited. They are well within the range of error inherent in the numbers.

Of more interest in the current context than remaining proved reserves are the figures for potentially discoverable reserves. These numbers have an even wider range. But they are quite encouraging. The indications are that substantial reserves remain to be discovered in the onshore and offshore United States. If prices are sufficient to cover the costs, these reserves will be forthcoming. There is, however, no sure proof of oil or gas other than the drillbit. If we are to enjoy the benefits of these potentially discoverable reserves, field market prices must encourage the exploration activity necessary to bring them into economic existence.

There have been various econometric studies of the discovery and production process. Econometrics, as reserve estimation, is also at best an imprecise science. Despite the fact that econometric analysis produces numerically precise coefficients complete with standard errors, it is most appropriate to view econometric analysis as providing orderly and systematic insight with regard to orders of magnitude. The proper way to regard the results of econometric analysis is with respect to the following question:

> "If we were to substantially increase the field market prices for natural gas, would we get:
> --substantial increases in new supplies?
> --a little increase in new supplies?
> --hardly any increase in new supplies?"

Econometric analyses of long-run oil and gas supply indicate that a substantial increase in field market prices would call forth substantial increases in new natural gas supplies. This evidence is consistent with estimates of potentially discoverable reserves. Higher field market prices would work to eliminate the natural gas dimension of the energy crisis.

54. Our conclusions are:

--field markets for natural gas are effectively competitive,
--the bidding process for offshore acreage is not collusive,
--the long-run marginal costs for incremental new gas supplies are substantially higher than the current average field prices, and
--if field market prices were allowed to rise to market clearing levels, new natural gas discoveries would eliminate the current shortage.

STATEMENT OF
RICHARD L. DUNHAM
CHAIRMAN, FEDERAL POWER COMMISSION
BEFORE
SUBCOMMITTEE ON ENERGY AND POWER
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
U. S. HOUSE OF REPRESENTATIVES

February 2, 1976

Mr. Chairman and Members of the Subcommittee, my remarks are directed at the proposals now pending in the House of Representatives to amend the Natural Gas Act to alleviate the present and future shortages in the supply of natural gas. I will primarily address Title II of H. R. 11265, generally referred to as the Krueger substitute amendment, and Title II of S. 2310 as passed by the Senate on October 22, 1975, generally referred to as the Pearson-Bentsen bill, with some reference to other proposals.

I emphasize that in my remarks I speak only for myself, and not for the Commission. The legal and technical analysis attached to my statement has been approved by the Commission.

Before discussing this long-term legislation, I would like to state, as I did before the Subcommittee on November 11, 1975, that in my position as Chairman of the Federal Power Commission, I have both a duty and a responsibility to administer the laws as they exist and I will do so to the best of my ability. My opinions as to desirable future policy will not affect the exercise of my responsibilities under the present law, and any amendments thereto that may be adopted.

There is today a shortage of natural gas in the interstate market, primarily because of the low price of interstate gas relative to the intrastate markets and to alternative fuels.

The Federal Power Commission cannot eliminate these disparities through its power to set wellhead prices for interstate gas. The price established must be "just and reasonable." The courts have interpreted this standard to mean that the Commission is tied to a historical cost base plus a return on capital.

We do not have authority to determine the just and reasonable price on other standards such as commodity value or market price. Such a basis provides neither the incentive for costly future drilling, nor a recognition of proper pricing in relation to alternate fuels. Thus, despite considerable efforts on the part of the Commission to attract gas to the interstate market through alternative pricing procedures, the ultimate resolution of this situation must come from Congress.

There has been considerable discussion and misunderstanding in the press about the impact of shortages, usually described as "curtailments". Curtailment, as used by the FPC, is simply the difference between the supply a pipeline has contracted to deliver and the amount it is actually able to supply. Curtailed users and others may well want to use even more natural gas, at the existing price, than the amounts contracted for. Thus, the true shortage may be even larger than the actual curtailment.

On November 11, 1975, the FPC issued a staff report projecting curtailments of firm service of 1.3 Tcf for the present winter heating season, or about 20%, of total firm service for that period. Reports on actual curtailments for the months of November and December are now in. The actual curtailments are running at only about 18% to 19% of firm service, thanks mainly to warmer than normal weather.

But the important point for the long term is not the exact amount of the shortage this winter or next. What is important is the quite evident long-run decline in gas supplies and availability. Every year since 1967 we have consumed more natural gas than we have added in new reserves (except for 1970, when the huge Prudhoe Bay Field was added to reserves).

Withdrawals from the bank, production of natural gas, are now running at more than twice the rate of new deposits, reserve additions. We cannot long continue down this road without confronting the most dangerous consequences.

Little of the new gas found has come to the interstate market. From 1969 to 1974, over 70 percent of new reserve additions, and almost 95 percent of net new reserves, in the lower 48 states have gone into the intrastate market.

Various proposals have been made to attract or force more gas into the interstate market for this winter. But the next year, and the next, we would be no better off than before. If we are to make the best use of this natural resource, both for ourselves and future generations, we must find a longer term solution.

Critics of deregulation have correctly noted the additional costs if new gas prices are permitted to rise to a level at which supply is sufficient to meet the demand. The rise in the average wellhead cost of gas to interstate consumers would be gradual, but could be substantial after a few years. For example, at the current level of interstate sales, an increase of 10 cents per Mcf in the average price at the wellhead would add about $1.2 billion to the annual gas bill of existing interstate consumers.

This estimate, however, considers only the costs to present gas users. The benefits to all consumers of price and supply increases should also be considered. In my opinion, the potential offsets are quite impressive.

Consumers would benefit considerably from access to gas by purchasers whose demand now goes unfilled, and who are currently forced to use high-priced alternative fuels. Present consumers would be spared the often enormous costs of conversion or plant relocation. There would also be a benefit in both economic efficiency and freedom if gas can be used by the industries and regions that value it most highly, as measured by the price they willingly pay. That would be preferable to allocating scarce supply on the basis of admittedly imprecise value judgments, a complicated administrative process, or simply luck in having old, locked-in contracts.

In addition, an increase in the volumes of natural gas delivered to customers of curtailed pipelines would in itself partially offset the higher costs to consumers. As deliveries increase, the high fixed cost of pipeline and distribution facilities are distributed over larger volumes of natural gas and the cost per unit declines. Conversely a decrease in gas supply will mean higher consumer charges for each unit used.

No one can state with precision the numerical balance of these costs and benefits, and this Committee has heard about all that can be said on the subject. I am convinced, however, that under existing legislation the prospect of improved gas supply is gloomy. The required artificially low prices and the imperfections of the regulatory process mean that legislative initiatives are needed to cope with the long-term problem. In this regard, I would call your attention to the conclusion of the January 14, 1976, GAO study on deregulation:

> In the end the energy consumer pays for the cost of energy in one form or another. In the aggregate, the consumer pays for his energy resources directly or indirectly--he pays in the price of natural gas, in the environmental impact, in higher taxes (due to taxes foregone), and in paying for higher cost energy alternatives since he cannot purchase natural gas. No matter what system is used to allocate resources, some consumers gain and some consumers lose.

Even if the basic choice is made for phased deregulation of new gas, there are a number of specific policy choices that can affect the size and incidence of consumer price changes. There are also some important administrative matters I would like to raise. Attached to my statement is a full summary and analysis by the Commission of the provisions of the bills I discuss today.

Both bills deregulate "new gas", but there are differences in the definition of new gas. Both would deregulate new onshore gas immediately, and offshore gas from Federal lands after 1980. The Krueger bill would allow deregulation of gas under contracts whose terms have expired (though it would not, as we interpret it, trigger contract clauses allowing renegotiation or termination on the event of deregulation). Pearson-Bentsen, on the other hand, provides for some continuing control with regard to such "rollover" gas.

Section 29 of Pearson-Bentsen requires the Commission to set a separate national rate for old natural gas which is the subject of an expiring contract. The rate, which would be adjusted every two years, will be based in part on traditional criteria such as historical costs attributable to exploration, development and production efforts.

The Commission is also directed to consider other factors, including prospective costs of operation, reworking, installation of additional compression and similar expenses necessary to prevent abandonment of recoverable reserves; and a rate of return on the sellers' initial capital investment sufficient to encourage an optimum level of investment in natural gas exploration and development. These standards are different from, though similar to, those standards now used by the Commission to set rates for flowing and new gas.

The Krueger bill would also deregulate gas from all new wells drilled. Pearson-Bentsen would deregulate only gas in a new or extended reservoir. The Krueger provision would provide an incentive for more thorough exploitation of reservoirs, as well as eliminating uncertainty as to price when a well is drilled. The Pearson-Bentsen approach could lead to enormous administrative problems in defining reservoirs. If the Pearson-Bentson language is adopted, Congress should consider providing the Commission with guidance as to the standards to be applied in judging whether a well is in an existing reservoir, rather than a new or extended reservoir.

The OCS ceiling, required under both bills for the period through 1980, would be a new type of undertaking for the FPC. The standards in Section 24 ask us to determine prospective costs of operation, and to determine rates that will call forth "optimum" amounts of production and reserves. We believe this can be done within a time comparable to our recent major national rate decisions.

Pearson-Bentsen would also require that to get the benefit of any increased rate, gas from the OCS must be dedicated for 15 years or the life of the reservoir, if less. There is no similar requirement in the Krueger Bill.

Another significant difference in the Krueger and Pearson-Bentsen bills concerns incremental pricing. Section 28 of Pearson-Bentsen directs the Commission to require all pipelines to make sales of old natural gas to natural gas distributing companies in proportion to the distributing company's requirements for service to residential users and small users. Thus, under Section 28, industrial and large commercial users would tend to pay the full new gas price for increased supplies, rather than only the average, or "rolled-in" price of all gas supplies, if State Commissions reflect this allocation in approving rates. The Krueger bill has no such provision. This is an important legislative determination for the Congress to make.

Some have contended that demand elasticity may be greater in the industrial and electric utility sectors than in the residential sector. If this were true, higher incremental pricing to industrial and large commercial users might promote the conservation of available natural gas supplies. On the other hand, "rolled-in" pricing would create a conservation incentive for all, and not just some users. Incremental pricing might create a small benefit, probably short term, to residential gas users at the cost of a detriment to all other families. Incremental pricing also complicates the general administrative problem for all parties. This is especially true since state commissions, not the FPC, set the ultimate rates paid by all gas users except direct industrial customers.

The proposed new Section 25 in both bills establishes a curtailment priority for natural gas used for essential agricultural purposes above that for any use other than public health and safety. Natural gas shortage and curtailment is a nationwide problem that affects every segment of our society. So long as such a necessity for allocation exists, I believe that the decisions should be made based on a detailed consideration of need categories. One segment of the economy should not be elevated above another on a blanket basis, especially since national needs may change rapidly.

Section 26 of Pearson-Bentsen would make the Commission's jurisdiction over the production, regasification, sale or transportation of synthetic or liquefied natural gas (SNG or LNG) coextensive with the Commission's future authority over natural gas. The Krueger bill would not.

The Commission's proposed jurisdiction would not include the feedstock of an SNG plant or the facilities for the production of such feedstock. The extension of our authority over SNG could create some regulatory obstacles to its development, but would facilitate the Commission's ability to plan with respect to the total national supply of natural gas. 1/

1/ The Commission's present jurisdiction over SNG is limited to the point where SNG becomes commingled with natural gas in a jurisdictional facility. See Section 2(5) of the Natural Gas Act and the U.S. Court of Appeals for the District of Columbia decision of July 28, 1975, in Alice Henry, et al. v. F.P.C., CADC Nos. 73-2090, 73-2166, 73-2236 and 74-1045 (1975).

There is also some indication that such certification authority would provide stability and certainty which would be helpful in attracting financing needed for LNG and SNG projects. Centralized decisionmaking on the siting and development of plants might help resolve some of the environmental, health and safety problems connected with the location of these non-traditional facilities. I firmly believe that these new projects must be planned and evaluated carefully, and FPC jurisdiction would provide a way to do that.

OPTIONAL FORM NO. 10
JULY 1973 EDITION
GSA FPMR (41 CFR) 101-11.6
UNITED STATES GOVERNMENT

Memorandum

TO : Richard L. Dunham, Chairman

DATE: January 29, 1976

FROM : General Counsel

SUBJECT: Legal and Technical Analysis of S. 2310 as Passed by the Senate on October 22, 1975; H.R. 11265 and H.R. 9159.

The following is a legal and technical analysis of the bills, S. 2310 as passed by the Senate on October 22, 1975, H.R. 11265, and H.R. 9159, all of which are pending before the Subcommittee on Energy and Power, House Interstate and Foreign Commerce Committee. The format of the analysis will be a section-by-section discussion of H.R. 11265, introduced by Congressman Krueger on December 18, 1975, with comparisons to related provisions in S. 2310 (Pearson - Bentsen) and H.R. 9159 (Fraser) when appropriate. Relatively little discussion will be given to Title I of both H.R. 11265 and S. 2310 since the effective dates of both titles expire on April 4, 1976. Furthermore this analysis will not focus "in depth" on the various provisions of H.R. 9159. This latter bill is very similar to S. 692 as reported by the Senate Commerce Committee on June 12, 1975. An FPC staff technical analysis of S. 692 appears at pages 85 to 99 of the Senate Commerce Committee Report of S. 692. 1/ The analysis of the subject legislation describes how the Natural Gas Act, 15 USC 717, *et seq*., would be amended and the resultant change in administration and policy formulated thereunder.

1/ S. Rep. No. 94-191, 94th Cong., 1st Sess. 85-99 (1975). The only major differences between S. 692 and H.R. 9159 are that the latter bill does not deregulate onshore natural gas sales by independent producers and H.R. 9159 would only allow a statutory base price range of 40¢ - 60¢/Mcf while S. 692 would allow a statutory base price range of 40¢ - 75¢/Mcf.

TITLE I, S. 2310 and TITLE I, H.R. 11265

Sections 101, 102 and 103 state the title, the findings and purposes, and the definitions for Title I of both bills.

Section 104 of both H.R. 11265 and S. 2310 directs the Commission to exempt from the provisions of the Natural Gas Act for up to 180 days any activities, operations, facilities or services relating to the transportation, sale and delivery, transfer, or exchange of natural gas from any sources other than offshore Federal lands. Only curtailing jurisdictional pipelines may enter into such exempted transactions as purchasers and then only to meet the needs of their high priority consumers. [2] Two provisos are contained in Section 104 of both bills which state: (1) that a purchasing pipeline may flow through the purchase costs of exempted transactions except where the pipeline purchases gas from an affiliate at a rate in excess of the price paid non-affiliated sellers in comparable sales transactions and (2) that natural gas sold and delivered or transported pursuant to any exemption granted under Section 104 shall not be or become subject to FPC jurisdiction because of the exempted transaction.

Section 104 of S. 2310 contains three provisos in addition to those contained in Section 104 of H.R. 11265: (1) that the sales price for an exempted transaction cannot exceed the highest wellhead price at which natural gas was sold during the period of June 1, 1975, through August 1, 1975, in the state in which the exempted transaction occurs; (2) that it shall be a violation of the Natural Gas Act for any natural gas distributing company to charge residential and small users (as defined by the Commission) rates which reflect any costs of an exempted transaction incurred by a purchasing pipeline; and (3) that contracts which would otherwise preclude or disallow an exempted transaction from occurring are deemed unenforceable with respect to the emergency transaction. The first two provisos would be added to Mr. Krueger's amendment to H.R. 9464 (see note 3 below) by the January 21, 1976, Brodhead amendment (see 122 Cong. Rec. H-187).

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[2] We note that Section 103(2) of H.R. 11265 would direct the Commission to define the term "high priority consumer of natural gas", while Sections 103(2) and 103(9) of S. 2310 would give statutory standards to the Commission for the determination of a "high priority consumer of natural gas."

Exempted transactions under Title I of both H.R. 11265 and S. 2310 may not be entered into after April 4, 1976 (See Section 107, H.R. 11265 and 108, S. 2310). 3/ The Commission currently allows exempted transactions under various provisions of its rules and regulations for up to sixty days in duration pursuant to the exemption authority provided in Section 7(c) of the Natural Gas Act. 4/ As the Natural Gas Act currently authorizes exempted transactions, and Title II of both bills would allow non-regulated on-shore 5/ producer sales to commence on April 5, 1976, (i.e., immediately upon termination of the exemption authority granted in Title I), enactment of Section 104 of Title I of either bill will have little if any impact on the Commission's current policy and administration concerning emergency sales of natural gas. Compare H.R. 11265, Sections 107 and 203 and S. 2310, Sections 108 and 203.

Section 105 of both bills authorizes the Administrator of the Federal Energy Administration, upon certain findings, to order power plants which are using natural gas as boiler fuel to substitute petroleum products therefor. Any natural gas released under this provision must be made available to high priority customers of curtailing pipelines and such pipelines are to provide compensation for specified increased costs incurred by power plants and their suppliers, e.g., fuel associated replacement costs and lost revenues to the pipeline suppliers. Such costs will ultimately be paid through increased rates and charges to high priority users, in proportion to volumes of

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3/ A December 8, 1975, amendment submitted in the Congressional Record by Congressman Krueger would change the April 4, 1976 termination date to April 15, 1976. See 121 Cong. Rec. 12022 (daily ed. Dec. 8, 1975).

4/ See Sections 2.68, 157.22 and 157.29 of the Commissions rules and regulations, 18 C.F.R. 2.68, 157.22 and 157.29.

5/ Note that currently exempted sales from FPC certification procedures from the Outer Continental Shelf are limited to the FPC's national rate for producer sales of new natural gas. (See 18 C.F.R. 157.29(d)). Neither H.R. 11265 nor S. 2310 authorize 180 day exempted sales from the Outer Continental Shelf.

natural gas consumed by such users, who are determined by the Commission to benefit as a result of a prohibition order.

As noted, Section 107 of H.R. 11265 and Section 108 of S. 2310 state that Title I of the respective bills "shall expire on midnight April 4, 1976." However, Section 105 of both bills authorizes the FEA Administrator to issue prohibition orders on the use of natural gas as boiler fuel when petroleum products are available until June 30, 1976. Such orders may take effect at any time prior to January 1, 1979. With this apparent difference between the expiration date for Title I and the termination date for this particular boiler fuel prohibition authority, we will assume that for purposes of Section 105 the June 30, 1976, date is the effective termination date for issuing prohibition orders on the use of natural gas as boiler fuel when petroleum products are available. 6/ The effect on FPC policy and administration of placing natural gas boiler fuel conversion authority in the FEA is discussed later in this memorandum.

Section 106 of both bills concerns propane pricing and allocation authority. We assume that enactment of Title IV of the Energy Conservation and Policy Act has rendered these provisions moot.

Section 107 of S. 2310 codifies the Commission's statement of policy issued in Order No. 533 7/ (no similar provision is contained in Title I of H.R. 11265). This section would expressly recognize the Commission's authority to issue a transportation certificate to a curtailing jurisdictional pipeline in order that the pipeline may transport natural gas sold from sources other than the Outer Continental Shelf which gas is purchased directly by a high priority consumer from an independent producer. In issuing such a certificate, the Commission need not review or approve the direct purchase price.

6/ It is assumed that the other amendments to the Energy Supply and Environmental Coordination Act (ESECA) contained in Section 105 of both bills have been rendered moot by enactment of Section 101 of the Energy Policy and Conservation Act, Pub. Law No. 94-163, Dec. 22, 1975, (89 Stat. 871).

7/ Order No. 533 was issued in Docket No. RM75-25 on August 28, 1975, 40 Fed. Reg. 41760, Order No. 533-A was issued November 10, 1975, 40 Fed. Reg. 54774.

For the same reasons stated in our analysis of Section 104 of both bills, (i.e. the short time period of effectiveness), there will be little if any impact on the Commission's current policy and administration of certificate applications pursuant to Order Nos. 533 and 533-A if section 107 of S. 2310 is enacted.

TITLE II, S. 2310; TITLE II, H.R. 11265; H.R. 9159

A. New Natural Gas Regulation--On-shore

Section 203 of both S. 2310 and H.R. 11265 would terminate as of midnight, April 4, 1976, FPC jurisdiction over sales of on-shore new natural gas to a natural gas company for resale in interstate commerce. New natural gas is defined in Section 204 of H.R. 11265 to mean natural gas which is: 8/

(1) dedicated to interstate commerce for the first time on or after January 1, 1975; 9/

8/ This definition of new natural gas is derived from the Commission's definition for new natural gas sold at the national rate pursuant to Opinion No. 699-H. See Section 2.56a(a)(2) of the Commission's rules, 18 C.F.R. 2.56a(a)(2).

9/ As with Opinion No. 699-H we will assume this definition will allow "new natural gas" pricing treatment for sales made pursuant to Sections 2.68, 2.70, 157.22, 157.29 and 2.75 of the Commission's rules as stipulated in Section 2.56a(a)(2)(ii).

(2) which is continued in interstate commerce after the expiration of a contract by its own terms on or after January 1, 1975; or 10/

(3) which is produced from wells commenced on or after January 1, 1975.

The definition for new natural gas in Section 204 of S. 2310 is more restrictive in scope than the definition provided for new natural gas in H.R. 11265. Section 204 of S. 2310 defines new natural gas to mean natural gas which is:

(1) dedicated to interstate commerce for the first time on or after January 1, 1975;

(2) produced from reservoirs discovered on or after January 1, 1975 or from a well initated and completed in an extension of a previously discovered reservoir on or after January 1, 1975; or

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10/ This segment of the definition for new natural gas in H.R. 11265 applies to such gas:

> ...which is continued in interstate commerce after the expiration of a contract by its own terms (and not through the exercise of any power to terminate or renegotiate contained therein) for the sale or delivery of such natural gas existing as of such date.... (emphasis added)

We interpret the above underlined language to preclude the exercise or triggering of any type of deregulation clause which may appear in any contract entered into for the sale of natural gas for resale in interstate commerce prior to date of enactment of this legislation.

(3) sold prior to date of enactment pursuant to a limited term certificate 11/ of 5 years or less or a temporary emergency contract. 12/

There are two major distinctions between the definitions provided for new natural gas in H.R. 11265 and S. 2310. First, H.R. 11265 would allow natural gas presently subject to the Commission's jurisdiction which is the subject of an expiring contract to be treated as new natural gas. S. 2310 would not allow this "roll over" gas to become new natural gas but would require continued regulation of such gas under a FPC formulated national ceiling as specified in section 29 of that bill and discussed, infra. We note that "roll over" gas under S. 2310 would continue to be subject to FPC regulation and thus the abandonment authorization requirements of section 7(b) of the Natural Gas Act would still adhere to persons selling such gas. That is, persons who sell natural gas for resale in interstate commerce wishing to cease that sale in interstate commerce must first seek and receive abandonment authorization from the Commission under S. 2310, when such natural gas is the subject of an expiring contract and does not otherwise qualify as new natural gas. Persons making the first sale of natural gas presently subject to the Commission's jurisdiction which is the subject of an expiring contract need not, under H.R. 11265, apply to the Commission for abandonment authorization if such gas qualifies as new natural gas under section 204(a)(8)(B) of this bill because first sales of new natural gas would no longer be subject to FPC jurisdiction. Abandonment requirements would still apply to new natural gas sold from off-shore Federal lands which is subject to the national ceiling specified in section 24 of both bills. However, abandonment requirements for such sales would cease on and after January 1, 1981.

11/ See Section 2.70(b)(3) of the Commission's rules, 18 C.F.R. 2.70(b)(3).

12/ The term temporary emergency contract includes sales of natural gas made pursuant to Sections 2.68, 157.22 and 157.29 of the Commission's rules, 18 C.F.R. 2.68, 157.22 and 157.29; and to emergency transactions under Sections 104 and 107 of S. 2310.

Secondly, H.R. 11265 applies the definition for new natural gas to gas which is produced from wells commenced on or after January 1, 1975. This definition would clearly apply to any new well regardless of whether existing acreage or reservoirs thereunder are currently dedicated to interstate commerce. On the other hand, S. 2310 applies the definition for new natural gas only to gas produced from reservoirs discovered on or after January 1, 1975 or from a well initiated and completed in an extension of a previously discovered reservoir on or after January 1, 1975. This would require a well-by-well determination in order to ascertain whether the well has been drilled in a new reservoir, or constitutes an extension of a reservoir beyond its previously defined limits, or is drilled to further the development of a previously defined reservoir. Such determinations would require complex geological and engineering analyses and would strain our limited resources, leading to administrative delays. We do note that this provision of S. 2310 places some limitation on new natural gas produced from new wells.

While the definitions for new natural gas vary between S. 2310 and H.R. 11265, Section 203 of both bills would terminate FPC jurisdiction over all first sales of on-shore [13] new natural gas in interstate commerce for resale. The focus of this termination of jurisdiction is not on the classification or type of person making the sale of new natural gas but rather is on the nature of the sale itself. The unregulated sale must be:

(1) a sale of new natural gas for resale;

(2) which sale is the first sale and not a subsequent sale;

(3) made in interstate commerce;

(4) which gas is not produced from off-shore Federal lands.

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[13] The term on-shore is used to include all lands other than off-shore Federal lands. Off-shore Federal lands are defined in Section 204(ii) of both H.R. 11265 and S. 2310 to mean any land or subsurface area within the Outer Continental Shelf, as defined in Section 2(a) of the Outer Continental Shelf Lands Act (43 USC 1331(a)).

It is important to note that under both S. 2310 and H.R. 11265 the Commission retains jurisdiction over second and succeeding sales in interstate commerce of natural gas for resale whether on-shore or off-shore. Furthermore, the Commission's authority to regulate the transportation in interstate commerce of all natural gas pursuant to the Natural Gas Act is not affected, nor is the Commission's authority to regulate sales for resale of any natural gas by any natural gas company which transports natural gas in interstate commerce altered. In other words, the current jurisdictional parameters of Section 1(b) 14/ of the Natural Gas Act concerning natural gas would remain the same under Section 203 of both bills with the exception of the termination of jurisdiction over the first sale of such new natural gas in interstate commerce for resale.

B. New Natural Gas Regulation--Off-shore.

Under new Section 24 to the Natural Gas Act, as contained in Title II of both S. 2310 and H.R. 11265, the Commission would be directed to establish by regulation, as soon as practicable after date of enactment, a national ceiling for the rates and charges for the sale or transfer in interstate commerce by any person of new natural gas produced from off-shore Federal lands on or after January 1, 1975, through December 31, 1980. The same definition of new natural gas for on-shore sales applies to off-shore sales under both bills. We assume that the Commission's regulatory rate authority over off-shore sales of new natural gas applies to "sales for resale" and does not extend to a direct sale rate by an off-shore seller to an end-user. We do not interpret the word "transfer", as it appears in this section, to expand the Commission's jurisdiction as set out in section 1(b) of the present Natural Gas Act.

14/ Section 1(b) is amended by Section 203 of S. 2310 and H.R. 11265 to read as Section 1(c).

The following standards are to be considered by the Commission in establishing the national ceiling:

(1) prospective costs attributable to the exploration, development, production, gathering, and sale of natural gas. (We note that "prospective" looks from the present into the future and is quite distinguishable from "historical");

(2) rates and charges necessary to encourage optimum levels of (A) the exploration for natural gas, (B) the development, production, and gathering of natural gas, and (C) the maintenance of proved reserves of natural gas. (We interpret this provision to encourage these "optimum levels" to mean the Commission will look to non-cost criteria such as economic incentives and market factors in addition to prospective costs in formulating the national ceiling);

(3) promotion of sound conservation practices in natural gas consumption necessary to contribute to the maintenance of a supply of energy resources at reasonable prices to consumers; and

(4) rates and charges that will protect consumers of natural gas from price increases that would, in the absence of a national ceiling during periods of actual or anticipated shortages, exceed the rates and charges necessary to achieve the objectives of (1) through (3) above. (We interpret this provision to mean the national ceiling should only be set at a level which will achieve factors (1) through (3) and will thus avoid any windfall profits which may occur as a result of excessive rates and charges).

The Commission has engaged in national rate-making in the past 15/ and should encounter no difficulty in establishing a national ceiling for new natural gas sales from off-shore Federal lands. If enacted, Congress will have mandated inclusion of extensive non-cost criteria in a rulemaking proceeding under section 24 of either H.R. 11265 or S. 2310. This is a departure from prevailing court interpretations requiring cost-based ratemaking. 16/ Furthermore, Congress will have provided the Commission with the authority to use its expertise and broad discretion in weighting the contribution of each of these four standards in a rulemaking proceeding under section 24 of either H.R. 11265 or S. 2310.

We perceive the national ceiling envisioned by section 24 to be analogous to the Commission's national rate for new natural gas sales, (Opinion No. 699-H), in the sense that both are actually a national base rate limitation on the maximum price for a qualifying sale. Various adjustments (upwards or downwards) could be made to a section 24 sale (if the Commission in its discretion so authorized) including: tax adjustments, Btu quality adjustments, gathering allowances, deliveries by a producer to an on-shore area, etc.

Under section 24(b) of H.R. 11265 and S. 2310 the Commission would monitor the effectiveness of the national rate and report annually thereon to Congress.

15/ See Opinions 699 through 699-H setting a national rate for new natural gas and the current biennial review of the national rate in Docket No. RM75-14.

16/ See letter (with attachment) dated August 28, 1975, to Chairman John D. Dingell, House Subcommittee on Energy and Power, from former Chairman John N. Nassikas. This letter and attachment provide a concise legal analysis of the Commission's duty as perceived by the courts to assure that regulated rates for natural gas production are cost-based.

Section 24(c) of both bills provides the Commission with the discretion to authorize a person to charge an amount in excess of the national ceiling for new natural gas produced from off-shore Federal lands from any high cost production area or vertical drilling depth as designated by the Commission pursuant to its rulemaking authority. In formulating this "add-on" to the ceiling rate, as statutorily prescribed by this subsection, the Commission would apply the same four factors used in establishing the national ceiling itself. [17]

Prior to the off-shore national ceiling no longer being subject to judicial review, Section 24(e) would direct the Commission to set an interim national ceiling rate equivalent to the average dollar valuation per barrel of crude oil used in computing royalties due the United States from all Federal lands during the calendar month ending thirty days prior to such computation. This interim ceiling would be expressed in dollars/1,000,000 Btu's and would be determined by dividing the average dollar valuation per barrel of crude oil by 5.8. If contracts entered into pursuant to the interim ceiling exceed the subsequently effective national ceiling, the Commission is expressly disallowed from ordering a reduction in rates and charges contained in the interim ceiling contract. 18/

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[17] It should be noted that Section 205(a) of both H.R. 11265 and S. 2310 specifically allows the Commission to authorize sales of new natural gas from off-shore Federal lands which exceed the national ceiling rate when such special relief will permit persons applying therefor to meet extraordinary expenses that could not be anticipated at the time the national ceiling was established or modified. This is similar to special relief allowed over the Opinion No. 699-H national rate. (See 2.56a(g) of the Commission's rules, 18 C.F.R. 2.56a(g)). This special relief envisioned by Section 205(a) is in addition to the provisions of Section 24(c). A person need not petition the Commission for a national ceiling price allowed under Section 24(c), with the exception of reporting that he qualifies for such price. Under Section 205(a), however, a person must apply to the Commission for special relief.

Section 24(d) of H.R. 11265 and S. 2310 addresses the treatment by the Commission of advance payments made to producers of new natural gas. Under this section any advance payment contract for new natural gas (if advance payments are authorized by the Commission) must be filed at least 60 days in advance of deliveries thereunder. The Commission may, after notice and hearing, require that the sales rate specified in such an advance payment contract be reduced or modified as necessary to repay in full to the advancing party the principal of the advance and any interest thereon, upon such terms and conditions as the Commission may determine proper in the public interest. We construe this authority to reduce or modify the

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18/ We note that Section 24(e) of S. 2310 would authorize producers to sell new natural gas at the national ceiling rate which is no longer subject to judicial review, whether or not such gas was contracted for prior to the effective date of the national ceiling. Section 24(e) of H.R. 11265 would authorize any producer, who has sold new natural gas during the period the interim ceiling was in effect, to have the benefit of the national ceiling once it is no longer subject to judicial review. We will give the same interpretation to both provisions: new natural gas sold subject to the interim rate may, if the contract so allows, be sold at the national ceiling rate once this latter rate is no longer subject to judicial review.

sales portion of advance payments contracts to be prospective in nature rather than retroactive. Furthermore, this section would not affect the Commission's discretion as to whether or not a natural gas company may enter into an advance payment contract. 19/ The filing of authorized advance payment contracts and subsequent Commission action thereon would apply to new natural gas produced from any source and not just off-shore Federal lands as this latter qualification is clearly deleted from subsection (d) of Section 24.

Section 24 of both S. 2310 and H.R. 11265 would terminate, as of January 1, 1981, FPC jurisdiction over the first sale of new natural gas produced from off-shore Federal lands. On and after January 1, 1981, the Commission will have the same remaining jurisdiction over new natural gas which is produced from off-shore Federal lands as it would over all other new natural gas.

C. Old Natural Gas Regulation

Section 205(b) and 206 of both H.R. 11265 and S. 2310 would amend Sections 4(e) and 5(a) of the Natural Gas Act, respectively. The following identical language would than appear in both Sections 4(e) and 5(a):

> "...[T]he Commission shall have no power .... (2) to order a decrease in the rate or charge made, demanded, or received for the sale or transfer of old natural gas by a natural gas company if such rate or charge shall have been previously determined or deemed to be just and reasonable pursuant to this act." (emphasis added)

19/ See Commmission Order on Remand From Court Opinion Terminating Investigation and Terminating Advance Payment Program With Conditions issued in Docket No. R-411 and RM74-4 issued on December 31, 1975, 41 Fed. Reg. 2776.

Currently, under Section 5(a) of the Natural Gas Act, the Commission may prospectively reduce rates after notice and hearing, which rates it determines are unjust, unreasonable, unduly discriminatory, or preferential and the Commission may set a rate which is just and reasonable. The Commission may, upon making the proper finding under Section 5(a), order such a reduction in a rate although the rate had previously been determined to be just and reasonable. The proposed amendments to Section 4(e) and 5(a) would "sanctify" rates for old natural gas already determined to be just and reasonable by the Commission, thus disallowing any prospective reduction of those particular rates in a subsequent Section 5(a) proceeding.

Section 204(a)(9) defines "old natural gas" to mean natural gas other than new natural gas. It is obvious that this definition applies to old natural gas subject to the Commission's jurisdiction and is not intended to extend the FPC's jurisdiction to gas not currently subject to the Commission's regulatory authority under the Natural Gas Act. Old natural gas is merely a type of "natural gas" as presently defined in Section 2(5) of the Natural Gas Act.

Proposed new Section 29 of the Natural Gas Act contained in Title II of S. 2310 would require the Commission to set a national rate for the sale of old natural gas which is the subject of an expiring contract. 20/ The rate, which is to be adjusted every two years, will be based on various factors including historical costs attributable to exploration, development and production efforts; prospective costs of operation, reworking, installation of additional compression and similar expenses necessary to prevent abandonment of old natural gas reserves otherwise recoverable; various add-ons; a rate of return on the sellers initial capital investment sufficient to encourage an optimum level of investment in natural gas exploration and development; and rates and charges that will avoid any windfall profits which may otherwise occur as a result of excessive rates and charges.

20/ No similar provision appears in Title II of H.R. 11265 as this bill provides "new natural gas" pricing treatment to natural gas which is the subject of an expiring contract. See Section 204(a)(8) of H.R. 11265 discussed, supra.

We note that the Commission currently allows the Opinion No. 699-H national rate for a sale of natural gas made pursuant to a contract which expires by its own terms on or after January 1, 1973. We will assume that the Section 29 ceiling rate for old gas contracts applies to contracts which expire on or after January 1, 1975. This would be consistent with earlier versions of Title II of S. 2310 which would have authorized new natural gas pricing treatment for contracts expiring on or after January 1, 1975. 21/

Title II of S. 2310 has one other provision concerning old natural gas which does not appear in Title II of H.R. 11265. Proposed new Section 28 would direct the Commission to require all pipelines to give first priority for sales of old natural gas to natural gas distributing companies to the extent such old natural gas is available to meet the requirements of each distributing company's residential users and small users. Thus, under Section 28, industrial and larger commercial users would pay an incrementally higher price for new natural gas. While the terms "residential users" and "small users" are not defined, we would give them the same status as priority of service category (i) in Section 2.78 of the Commission's rules. 22/ Furthermore we would apply the definitions for "residential" and "commercial" in determining who qualifies as residential and small users as those definitions are found

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21/ See the October 20, 1975 print for Amendment No. 919 to S. 2310 at 24, lines 17 to 22. (Section 204(a) definition for "new natural gas"). Amendment No. 919, as amended and modified, was adopted in lieu of S. 2310 by the Senate on October 22, 1975, and then given the engrossed Bill No. S. 2310.

22/ 18 C.F.R. 2.78(a)(1)(i). The small user pricing benefit allowed persons under Section 28(d) who use natural gas for essential agricultural purposes which use does not exceed 50 Mcf on an average day will be interpreted to mean a use which does not exceed 50 Mcf on a peak day average.

in Section 2.78(b)(1 and 2) of the Commission's rules. 23/ The term "pipeline" is not defined in S. 2310, however, we would construe this term to apply only to natural gas companies subject to the Commission's jurisdiction which transport natural gas in interstate commerce. Although not stated in Section 28, we assume that state and local regulatory commissions will assure that distributing companies do in fact adhere to the incremental pricing concept of this section. 24/

D. New Natural Gas Regulation Under H.R. 9159 25/

Enactment of this legislation would extend the Commission's jurisdiction to sales of new natural gas in the currently unregulated intrastate market (Sections 202(a) and 203). The Commission would be directed to establish a base price for all producer sales of new natural gas whether they are made in interstate or intrastate commerce (Section 203). New natural gas would be gas not dedicated to interstate or intrastate commerce prior to January 1, 1975 (Section 202(a)). To qualify for new natural gas treatment, the dedication must be for a term of 20 years or until earlier depletion. Dedications of more than 10 years but less than 20 years would receive 75% of the allowable price for new natural gas. 26/

23/ 18 C.F.R. 2.78(c)(1), 18 C.F.R. 2.78(c)(2).

24/ We interpret Section 28(c) as authority to require tariff filings by jurisdictional pipelines to assure that the incremental pricing concepts of this section are met. This is not to be construed as authorizing the Commission to order interconnections or allocations of natural gas between pipelines.

25/ For the impact of H.R. 9159 on the Commission's current policies and administration under the Natural Gas Act see note 1, *supra*.

26/ The allowable wellhead price for "old natural gas" would, in most instances, be frozen at existing rate levels (see Section 205). Old natural gas is defined as "natural gas that, prior to January 1, 1975, was dedicated to interstate commerce...." (See Section 202(10)).

The base price for new natural gas sales must fall within a cost-based range of 40¢/Mcf to 60¢/Mcf. Various adjustments may be made to the base price: an inflationary adjustment factor; a 2% annual "incentive"; a special price for high cost production of natural gas and for cost of production of synthetic and liquefied natural gas; and additional adjustments for (e.g.) gathering allowances and severance taxes. Pipelines may only flow-through purchase costs of new natural gas on a dollar-for-dollar basis.

H.R. 9159 does not distinguish between the regulation of sales of gas produced from on-shore and off-shore lands. However, the bill does permit small producers to market new natural gas at 150% of the allowable rate for new natural gas as discussed in the preceding paragraph (Section 203(k)). A small producer is defined to mean a person not affiliated with a pipeline who, together with all other affiliated small producers, has not sold more than 10,000,000 Mcf of natural gas in the year preceding the year in which he seeks to qualify as a small producer (Section 202(18)). 27/

27/ The Commission currently allows small producers to sell new natural gas in interstate commerce at a rate at least equal to 130% of the FPC's national rate. See Opinion No. 742, 40 Fed. Reg. 41769, applications for rehearing pending.

E. Regulation of Pipelines.

Sections 205(b) and 206 of both H.R. 11265 and S. 2310 provide that jurisdictional pipelines may flow through all rates and charges for purchases of new natural gas except:

(1) rates and charges for new natural gas produced from off-shore Federal lands which exceed the national ceiling established under section 24, and 28/

(2) rates and charges for an affiliate sale of any new natural gas to the purchasing pipeline which exceed rates and charges for comparable sales by any person who is not affiliated with a jurisdictional pipeline.

The Commission's current policy is to authorize pipelines to flow through only those rates and charges which are deemed just and reasonable. 29/ The effect of sections 205(b) and 206 would be a Congressional determination that all rates and charges for the sale of new natural gas to a jurisdictional pipeline are just and reasonable with the narrow exceptions stated above. Note that sections 205(b) and 206 amend sections 4(e) and 5(a) of the Natural Gas Act, respectively, which latter sections are the procedural and substantive guidelines for determining the justness and reasonableness of rates under the Natural Gas Act.

This legislation cannot be interpreted to mean that the Commission could do indirectly under its section 7(c) certification authority what it is statutorily pre-empted from doing under sections 4 and 5 of the Natural Gas Act. That is, the Commission, in considering an application by a jurisdictional pipeline under section 7 for any certificate of public convenience and necesity, may not consider as unjust or unreasonable the

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28/ But see note 17, *supra*, which discusses special relief sales which may exceed the national ceiling established under section 24 and section 205(a). It should also be noted that a pipeline purchasing new natural gas from off-shore Federal lands can only flow through the sales price even if that price is below the national ceiling price. In such an instance the purchasing pipeline may not add on to the purchase price in its own resale of the new natural gas an amount that equals the difference between the sales price and the national ceiling. The pipeline is limited to a "tracking" of the purchase cost.

29/ See *FPC* v. *Texaco*, 417 U.S. 380 (1974).

sales price for new natural gas delivered into interstate commerce from on-shore lands on or after January 1, 1975, or for new natural gas delivered into interstate commerce from off-shore Federal lands on or after January 1, 1981. 30/ With respect to off-shore deliveries of new natural gas between January 1, 1975 and January 1, 1981, the Commission would make an "in-line" determination, in considering a certificate application, that the identified sales price is at or below the section 24 national ceiling (or interim ceiling) or the sales price justifiably exceeds the national ceiling under a "special relief" classification. In no other instances may the Commission's certification authority be exercised to disallow the flow through of purchase costs by a jurisdictional pipeline of new natural gas.

F. Broadened Information Gathering Authority.

Section 207 of both H.R. 11265 and S. 2310 and section 207(g) of H.R. 9159 all delegate to the Commission broader than present information gathering authority under section 14 of the Natural Gas Act. These provisions all would basically confer upon the Commission the authority it has sought from the Congress for twenty years 31/ to collect publish and disseminate information with respect to all aspects of the natural gas industry "whether or not otherwise subject to the jurisdiction of the Commission."

30/ The necessity for producers to apply for certificates of public convenience and necessity for sales of new natural gas in these instances would be obviated by section 203 of both H.R. 11265 and S. 2310.

31/ The recommendation was included in S. 1880, 84th Congress, S. 2259, 86th Congress, S. 1603 and H.R. 693, 87th Congress, 1st Session, and in Section 7 of S. 2744 and of H.R. 10866, 87th Congress, 2d Session. The proposal was later introduced as a separate measure, S. 3343 and H.R. 12011, 87th Congress, 2d Session, implementing the President's March 41, 1962 Consumer Message, and reintroduced as S. 1463 and H.R. 5867 in the 88th Congress; S. 1550 and H.R. 5871 in the 89th Congress; S. 1720 and H.R. 8548 in the 90th Congress; S. 3900, S. 4290 and H.R. 19510 in the 91st Congress; S. 401, S. 701 and H.R. 3668 in the 92d Congress; and in the 93d Congress as S. 1829 and H.R. 8257.

This investigatory jurisdiction is the same in substance and effect as that authority already conferred upon the FPC with regard to the electric industry under section 311 of the Federal Power Act.

We note that section 207 of both H.R. 11265 and S. 2310 would place two additional requirements on the Commission with respect to information gathering authority.

(1) If the Commission, in making studies, investigations and reports under section 14 of the Natural Gas Act utilizes studies, investigations, and reports of Federal or state agencies or of the natural gas industry, such external studies, investigations, and reports shall be based on information developed or completely reviewed for accuracy, after date of enactment, and 32/

(2) Within ninety days of the date of enactment of this legislation, the Commission is directed to make a comprehensive natural gas reserves study to the President and the Congress. Such study shall be reviewed and revised annually thereafter.

We interpret this amendment to section 14 of the Natural Gas Act as providing the Commission with authority to order independent staff audit and verification of any information gathered under the various provisions of section 207. Furthermore, we interpret the language "whether or not otherwise subject to the jurisdiction of the Commission" to cover the entire scope of natural gas industry activities including information relating to end-use consumption by customers of distribution companies.

32/ We do not interpret section 207(2) as restricting the Commission to industry or other government data.

G. Curtailment Priorities.

Proposed new section 25 to the Natural Gas Act contained in both H.R. 11265 and S. 2310 would, if enacted, basically rewrite the Commission's priority of service categories for curtailing pipelines as specified in Commission Order No. 467-B, 38 Fed. Reg. 6384, and listed in section 2.78(a)(1) of the Commission's rules and regulations. 33/ The new service categories to be served by curtailing pipelines in order of priority are:

(1) natural gas service to residential users, small users, hospitals, and similar services vital to public health and safety;

(2) essential agricultural, food processing, or food packaging uses; 34/

(3) natural gas service to users using natural gas as a raw material and uses other than boiler fuel for which there is no substitute regardless of whether such users purchase natural gas under firm or interruptible contracts;

(4) any other lower priority of service categories which the Commission may deem appropriate.

We note that these categories are statutory directives to jurisdictional pipelines, through the Commission, directing such pipelines to formulate, when necessary, curtailment plans in a specified manner. We do not construe any allocation or pipeline interconnection authority from proposed section 25. 35/

33/ See 18 C.F.R. 2.78(a)(1)(i through ix).

34/ Note that under this priority of service category, the Secretary of Agriculture shall determine by rule the agricultural, food processing, or food packaging purposes for which natural gas is essential. The Secretary of Agriculture shall also certify to the Commission the amount of natural gas which is necessary for such essential uses to meet requirements for full food and fiber production.

35/ See section 209 of H.R. 9159 which contains a similar restructuring of the FPC's priority of service categories and then also delegates interconnection and allocation authority.

Section 25(c) of S. 2310, entitled "Prompt Curtailment Decisions" states: 36/

> The Commission shall decide applications for relief under subsections (a) and (b) as soon as practicable, but in no event later than 120 days of the time such applications are filed.

We read this provision as requiring the Commission to issue a final order (subject to rehearing) for relief from a curtailment plan within 120 days of the date the petition for relief is accepted for filing. This subsection addresses the Commission's current policy with respect to applications for "emergency relief" from curtailment plans as provided in Order No. 467-C, 39 Fed. Reg. 12984. 37/

H. Commission Jurisdiction Over Synthetic Gas.

Proposed new section 26 to the Natural Gas Act contained in S. 2310 would delegate to the Commission extensive authority over synthetic natural gas (SNG). 38/ The Commission currently has no jurisdiction over SNG until it enters into a natural gas stream (i.e. jurisdiction adheres at the tap and valve point of a jurisdictional facility). 39/ Section 25 of S. 2310 would subject to the jurisdiction and authority of the Commission, with respect to SNG, any plant used for the production or regasification of SNG, any sales or transportation of SNG, and

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36/ No similar provision appears in H.R. 11265.

37/ See section 2.78(b) of Commission's rules, 18 C.F.R. 2.78(b).

38/ No similar provision appears in H.R. 11265 although a similar provision is contained in Section 203(d)(2) of H.R. 9159.

39/ See Henry v. FPC, F. 2d , No. 73-2090, (D.C. Cir. July 28, 1975).

any person owning and, or operating such plant. 40/ Expressly exempted from Commission jurisdiction under section 26 is the feedstock of an SNG plant (e.g. coal, naptha, propane) or facilities for the production of such feedstock, unless the feedstock is natural or manufactured gas.

I. FPC Prohibition Authority Over Natural Gas Boiler Fuel Use.

Appearing as section 26 in H.R. 11265 and section 27 in S. 2310 are very similar amendments to the Natural Gas Act which would direct the Commission, upon certain findings, to prohibit existing and future boiler fuel use of natural gas. 41/ Boiler fuel is defined in section 204(7) of both bills to mean:

> "/T/he use of natural gas as the source of fuel in a generating unit of more than 25 megawatts rated net generating capacity or in any unit which is part of an electric utilities system with a total net generating capacity of more than 150 megawatts for the purpose of generating electricity for distribution."

Subsection (a) directs the Commission to prohibit, by rule, boiler fuel use of natural gas affecting commerce not contracted for prior to January 1, 1975. We read the words "affecting commerce" as extending the Commission's jurisdiction to prohibit boiler fuel use of natural gas to all boiler fuel consumption whether or not such boiler fuel use of natural gas is presently subject to the Commission's pipeline curtailment jursidiction. 42/ We interprete this

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40/ We note that section 26 also makes reference to liquefied natural gas (LNG). The court's holding in Distrigas Corp. v. FPC, 495 F. 2d 1057 (D.C. Cir. 1974), confirms that the Commission has extensive jurisdiction over LNG. We read section 26 as a Congressional affirmance that the Commission may treat its LNG jurisdiction as coterminous with its natural gas jurisdiction.

41/ A similar provision is contained in section 208 of H.R. 9159.

42/ This interpretation would comport with our interpretation of section 207, *supra*, pp. 19-20.

prohibition authority as a mandate from Congress which would be distinct and in addition to the Commission's transportation jurisdiction as presently stated in section 1(b) of the Natural Gas Act.

In prohibiting boiler fuel use not contracted for prior to January 1, 1975, the Commission may not exercise such authority if, upon petition by a user, the FPC determines that:

(1) alternative fuels, other than crude oil or products refined therefrom and propane, are not available to such user; or

(2) it is not feasible or practicable to utilize such alternative fuels at the time of such Commission determination.

In determining availability, feasibility, and practicability, under these standards, the Commission will look to economic factors such as costs of conversion and costs of alternative fuels in addition to other criteria.

Subsection (b) states that boiler fuel use of natural gas contracted for prior to January 1, 1975, will be terminated by the Commission upon expiration of the contract or twelve years after date of enactment of this provision, whichever is earlier. While the words "affecting commerce" do not appear in this subsection, we assume that it would be the intent of Congress to apply boiler fuel prohibition jurisdiction consistently, whether such use was contracted for prior to or on or after January 1, 1975. The same limiting standards apply in this subsection as they do to the exercise of prohibition authority in subsection (a).

Subsection (c) states that the Commission shall not, with respect to contracts entered into prior to January 1, 1975, except as provided in subsection (b); (1) modify, amend or abrogate such contracts for the sale or transportation of natural gas for boiler fuel use; (2) modify, amend, or abrogate certificates of public convenience and necessity authorizing such sale or transportation except upon application for abandonment authorization by a holder of such a certificate; or (3) prevent, impair, or limit, either directly or indirectly, the performance of any such contract or certificate.

We construe this provision to "santify" pre-January 1, 1975, contracts and certificates for boiler fuel sales and transportation of natural gas for a period up to twelve years from date of enactment. If either the contract or the certificate expire prior to that date, then prohibition will be forthcoming under the provisions of subsection (b). In addition, we do not read clause (3) of subsection (c) as overriding the priority of service categories for curtailing pipelines set forth in section 25 of both H.R. 11265 and S. 2310. This construction is affirmed by the proviso in subsection (c) which states:

> . That the provisions of this subsection shall not otherwise modify or affect the authority of the Commission under this Act (i.e., the Natural Gas Act as amended).

The boiler fuel prohibition provisions of H.R. 11265 and S. 2310 do not authorize the Commission to prohibit the burning of natural gas by powerplants for the purpose of operating pollution abatement systems. Nor may the Commission prohibit the boiler fuel use of natural gas for the necessary processes of ignition, startup, testing, and flame stabilization by a facility, or for the purpose of alleviating short-term air quality emergencies or any other danger to the public health, safety, or welfare. The Commission may not exercise its authority to impair any requirement in any State or Federal law pertaining to safety or environmental protection. In addition the Commission is directed to coordinate the implementation of this boiler fuel prohibition authority with the various State Commissions pursuant to section 17 of the Natural Gas Act. Finally, section 27(e) of S. 2310 (no similar provision appears in H.R. 11265) states:

> The Administrator (of FEA) shall, by rule promulgated no longer than 30 days after enactment of this Act, prohibit all uses of natural gas that he determines are solely for ornamental or decorative purposes. Such gas prohibition shall be limited to uses which are outside of a residence or dwelling which has the installed capacity to use electricity. The prohibition shall take effect not later than 60 days after enactment of this title.

We are aware that section 101 of the Energy Policy and Conservation Act has extended FEA's authority under section 2 of the Energy Supply and Environmental Coordination Act (ESECA): (1) to prohibit existing powerplants from burning natural gas as a primary energy source if such facility has the capability to burn coal and (2) to order that powerplants in the early planning process be designed and constructed so as to be capable of using coal as their primary energy source (i.e. boiler fuel). As stated earlier in this memorandum, FEA would, under Title I of H.R. 11265 and S. 2310, have the authority under ESECA to prohibit powerplants from burning natural gas if such powerplants have the capability to convert to petroleum products and petroleum products are available. This latter authority, as stated in Title I, may be exercised until July 30, 1976.

There is a good deal of similarity between FEA's prohibition and construction order authority under ESECA and the natural gas boiler fuel prohibition authority which would be delegated to the Commission upon enactment of either S. 2310 or H.R. 11265. 43/ Both agencies have a developed expertise regarding natural gas end-use of boiler fuel. It is assumed that, if the natural gas boiler fuel prohibition provisions of either H.R. 11265 or S. 2310 are enacted, FEA and FPC will coordiante their efforts to assure that the statutory mandates of ESECA and the Natural Gas Act are met.

We would further note that the proposed boiler fuel prohibition authority of these bills would expand the current regulatory responsibilities of the Commission. Adequate funds and manpower should be made available in order to correctly execute this new jurisdictional authority.

43/ As stated earlier, the FPC would not be authorized to issue a prohibition order if crude oil, crude oil products, or propane are the only available alternative fuels to supplant natural gas as boiler fuel. Thus coal would become the primary "available" fuel under either H.R. 11265 or S. 2310 and coal is the target fuel under ESECA.

J. Delegation of Authority to the Secretary of Interior (sections 30 and 31 of S. 2310).

Section 30 would authorize the Secretary of the Interior to require, in emergency situations, the maximum efficient rate of production of oil or natural gas produced from Federal lands. We assume that section 106 of the Energy Policy and Conversion Act has rendered this provision moot.

Section 31 would direct the Secretary of the Interior, upon commencement of production of natural gas from any lease on Federal lands, to offer to the public and to sell by competitive bidding for not less than its fair market value, that proportion of natural gas from such leases which is due the United States as royalty natural gas.[44] The Commission and FEA will assist the Secretary of Interior in determining if an emergency shortage of natural gas exists in or is threatnening any region. In addition, the Secretary, with the assistance of FEA and FPC, will report to Congress within sixty days of enactment of this section any legislative proposals which would facilitate and maximize the efficient and effective use of royalty natural gas sold by competitive bidding under this provision.

K. Commingling of Interstate and Intrastate Natural Gas In A Jurisdicitonal Pipeline.

Section 209 of both H.R. 11265 and S. 2310 would amend present section 1 of the Natural Gas Act by adding the following new subsection at the end thereof:

> Nothing in this Act shall prevent the intrastate transportation of natural gas first sold in commerce after the date of enactment of this subsection in an interstate pipeline as long as such intrastate transportation does not prevent service necessary to meet the requirements of interstate consumers and the rates for such transportation reflect the fully distributive costs of the interstate facilities used therein, and the provisions of this Act shall not apply to any such intrastate transportation or the facilities utilized in such service.".

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[44] This "royalty in kind" provision would apply to any lease entered into after date of enactment of this section.

We read this provision to mean that natural gas which is produced and consumed totally within the same state and which never leaves that same state but which, for purposes of transportation, enters a jurisdictional facility, may not become subject to the Commission's jurisdiction. This statutory provision would legislatively recognize the commingling of interstate and intrastate natural gas and, as we would interpret the provision, leave to the Commission the ultimate resolution of FPC jurisdiction. [45]

Drexel D. Journey

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[45] For previous court holdings on the commingling doctrine see: *California, et al.*, v. *Lo-Vaca Gathering Co., et al.* 379 U.S. 366 (1964); and *City of Hastings* v. *FPC*, 221 F. 2d 31 (D.C. cir., 1954), Cert. denied, 349 U.S. 920 (1955.)

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